APPENDIX 10.1.5

PSD APPLICATIONS/PERMITS

[Note: The application requesting prevention of significant deterioration (PSD) approval for the project is contained in this appendix. Appendix 10.4.2 contains a copy of the air construction and PSD Permit for Martin Units 8A and 8B.]

AIR PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS FOR FPL MARTIN UNIT 8 COMBINED CYCLE PROJECT MARTIN COUNTY, FLORIDA

Prepared For:
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

January 2002
0137609

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APPLICATION FOR PERMIT

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Florida Power and Light Company**	
2. Site Name: **Martin Power Plant**	
3. Facility Identification Number: **0850001**	[ ] Unknown
4. Facility Location: Street Address or Other Locator: **7 miles N. Indiantown on S.R. 710** City: **Indiantown** County: **Martin** Zip Code: **34956**	
5. Relocatable Facility? [ ] Yes [**X**] No	6. Existing Permitted Facility? [**X**] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **K.H. Simmons, Manager of New Capacity Projects, Environmental Services**
2. Application Contact Mailing Address: Organization/Firm: **Florida Power and Light Company** Street Address: **700 Universe Blvd.** City: **Juno Beach** State: **FL** Zip Code: **33408**
3. Application Contact Telephone Numbers: Telephone: (**561**) **691 - 2216** Fax: (**561**) **691 - 7049**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	2-1-02
2. Permit Number:	0850001-010-AC
3. PSD Number (if applicable):	PSD-FL-327
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: __________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: __________________

Operation permit number to be revised: __________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: __________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised: __________________

Reason for revision: __________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[X] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **John M. Lindsay, Plant General Manager**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Florida Power and Light Company, Martin Plant** Street Address: **P.O. Box 176** City: **Indiantown** State: **FL** Zip Code: **34956**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(561) 597 - 7106** Fax: **(561) 597 - 7416**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [✓], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* JM Lindsay Signature 1/29/02 Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 336 - 5600** Fax: **(352) 336 - 6603**

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Kennard F. Kosky　　　　1/31/02

Signature　　　　Date

(seal) 7/24

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
8A	GE Frame 7FA Combustion Turbine	AC1A	
8B	GE Frame 7FA Combustion Turbine	AC1A	
8C	GE Frame 7FA Combustion Turbine	AC1A	
8D	GE Frame 7FA Combustion Turbine	AC1A	
--	Natural Gas Heaters	AC1A	
--	Cooling Tower	AC1A	

Application Processing Fee

Check one: [ ] Attached - Amount: $: ____________ [X] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Construction of 2 170-MW GE FRAME 7FA combined cycle combustion turbines (CT), 4 heat recovery steam generators (HRSGs) and one steam turbine with associated electric generator (see PSD Report).**
2. Projected or Actual Date of Commencement of Construction: **May 2003**
3. Projected Date of Completion of Construction: **December 2005**

Application Comment

See PSD Report. Application fee not applicable since review is site certification review, which has an applicable fee.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17** East (km): **543.1** North (km): **2992.9**			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **27 / 3 / 13** Longitude (DD/MM/SS): **80 / 33 / 46**			
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters): **Project consists of two 170-MW dual-fuel, General Electric Frame 7FA CT/HRSGs that will use dry low-nitrogen oxide combustion technology when firing natural gas and water injection when firing distillate fuel oil, along with selective catalytic reduction (SCR) when in combined cycle mode. Each CT/HRSG will operate up to 8,760 hours per year. Current facility Title V Permit No. 0850001-004-AV.**			

Facility Contact

1. Name and Title of Facility Contact: **Willie Welch, Environmental Specialist**
2. Facility Contact Mailing Address: Organization/Firm: **Florida Power and Light Company** Street Address: **P.O. Box 176** City: **Indiantown** State: **FL** Zip Code: **34956**
3. Facility Contact Telephone Numbers: Telephone: **(561) 597 - 7211** Fax: **(561) 597 - 7416**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [X] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [X] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): **CT and HRSGs are subject to NSPS Subpart GG and Da, respectively.**	

List of Applicable Regulations

See Attachment PMR8-EU1-D.	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
PM	**A**				**Particulate Matter-Total**
VOC	**A**				**Volatile Organic Compounds**
SO_2	**A**				**Sulfur Dioxide**
NO_x	**A**				**Nitrogen Oxides**
CO	**A**				**Carbon Monoxides**
PM_{10}	**A**				**Particulate Matter-PM_{10}**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1.	Area Map Showing Facility Location: [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
2.	Facility Plot Plan: [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
3.	Process Flow Diagram(s): [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
4.	Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
5.	Fugitive Emissions Identification: [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
6.	Supplemental Information for Construction Permit Application: [X] Attached, Document ID: PSD Report [ ] Not Applicable
7.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [ ] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [ ] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:____________________________) [ ] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA CT/HRSG. Designated as Unit 8A. The CT is an existing emission unit.

4. Emissions Unit Identification Number:
ID:

[ ] No ID
[X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a GE Frame 7FA CT/HRSG operating in simple and combined cycle mode (see PSD Report).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Natural Gas Firing** • Simple Cycle - Dry Low NO_x combustion • Combined Cycle - SCR **Distillate Fuel Oil Firing** • Water Injection • Combined Cycle - SCR	
2. Control Device or Method Code(s):	25, 28, 65

Emissions Unit Details

1. Package Unit: Manufacturer: General Electric		Model Number: 7FA	
2. Generator Nameplate Rating:	172	MW	
3. Incinerator Information:			
Dwell Temperature:			°F
Dwell Time:			seconds
Incinerator Afterburner Temperature:			°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**1,600**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,811 MMBtu/hr (ISO-LHV) and 180 MW; Higher power modes – gas is 1,680 MMBtu/hr and 182 MW. The maximum heat input for the HRSG duct burners is 550 MMBtu/hr.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PMR8-EU1-D for operational requirements.
See PSD Report for permitting requirements.

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through the HRSG stack during combined cycle operation and through the bypass stack during simple cycle operation.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **HRSG-120 / Bypass-80** feet	7. Exit Diameter: **HRSG-19 / Bypass-22** feet
8. Exit Temperature: **202 / 1,116** °F	9. Actual Volumetric Flow Rate: **1,004,150 / 2,389,462** acfm	10. Water Vapor: **8.4** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Stack parameters for ISO operating condition firing natural gas above; for oil 295 / 1,098°F and 1,193,859 / 2,735,300 ACFM; HPM 205 / 1,130°F and 1,014,759 / 2,426,858 (combined cycle / simple cycle).

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

Distillate (No. 2) Fuel Oil

2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **14**	5. Maximum Annual Rate: **7,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**

10. Segment Comment (limit to 200 characters):

Million Btu per SCC Unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV of 18,300 Btu/lb, ISO conditions, 500 hrs/yr operation.

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

Natural Gas

2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.68**	5. Maximum Annual Rate: **14,754**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**

10. Segment Comment (limit to 200 characters):

Based on 950 Btu/cf (LHV); ISO conditions and 8,760 hrs/yr operation.

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025, 028	065	EL
CO			EL
VOC			EL
PM_{10}			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** b/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if > 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during gas firing - all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)**

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **GE, 2000; Golder**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   See PSD Report, Section 2.0; and Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil**
4. Equivalent Allowable Emissions: **103.1** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters):

   Fuel Sampling

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Oil firing max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **13.3** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. natural gas firing CT with duct firing, 1 gram/100 cf - 35°F, 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **10.6** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 42 ppmvd, CC - 12 ppmvd**	4. Equivalent Allowable Emissions: **333.8 / 95.4** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions **2** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 9 ppmvd, CC - 2.5 ppmvd**	4. Equivalent Allowable Emissions: **61.3 / 24.2** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **105.1** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. HPM firing; 35°F; 100% load; TPY @ 59°F, 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd - Baseload**	4. Equivalent Allowable Emissions: **68.1** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **28.6** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **89.0** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **HPM and duct firing; 80°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

See PSD Report, Section 2.0; and Appendix A. VOC emissions exclusive of background VOC concentrations.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**	4. Equivalent Allowable Emissions: **6.0** lb/hour **27.6** tons/year

5. Method of Compliance (limit to 60 characters):

EPA Method 25A; high and low load

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6.2 ppmvd, includes CT and duct burner**	4. Equivalent Allowable Emissions: **11.69** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvw**	4. Equivalent Allowable Emissions: **2.8** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: HPM firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if >400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75 have been installed for this unit. Information previously submitted to DEP.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **DEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date: **01 Jan 2002**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD Report [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD Report [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

ATTACHMENT PMR8-EU1-D

APPLICABLE REQUIREMENTS LISTING

ATTACHMENT PMR8-EU1-D

Applicable Requirements Listing

EMISSION UNIT ID: EU1

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(7)(b)37. (State Only)	NSPS Subpart GG
62-204.800(7)(c) (State Only)	NSPS authority
62-204.800(7)(d)(State Only)	NSPS General Provisions
62-204.800(12) (State Only)	Acid Rain Program
62-204.800(13) (State Only)	Allowances
62-204.800(14) (State Only)	Acid Rain Program Monitoring
62-204.800(16) (State Only)	Excess Emissions (Potentially applicable over term of permit)

Stationary Sources-General:

62-210.650	Circumvention; EUs with control device
62-210.700(1)	Excess Emissions;
62-210.700(4)	Excess Emissions; poor maintenance
62-210.700(6)	Excess Emissions; notification

Acid Rain:

62-214.300	All Acid Rain Units (Applicability)
62-214.320(1)(a),(2)	All Acid Rain Units (Application Shield)
62-214.330(1)(a)1.	Compliance Options (if 214.430)
62-214.340	Exemptions (new units, retired units)
62-214.350(2);(3);(6)	All Acid Rain Units (Certification)
62-214.370	All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)
62-214.430	All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:

62-296.320(4)(b)(State Only)	CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	All Units (Test Runs-Mass Emission)
62-297.310(2)(b)	All Units (Operating Rate; other than CTs; no CT)
62-297.310(3)	All Units (Calculation of Emission)
62-297.310(4)(a)	All Units (Applicable Test Procedures; Sampling time)
62-297.310(4)(b)	All Units (Sample Volume)
62-297.310(4)(c)	All Units (Required Flow Rate Range-PM/H_2SO_4/F)
62-297.310(4)(d)	All Units (Calibration)
62-297.310(4)(e)	All Units (EPA Method 5-only)
62-297.310(5)	All Units (Determination of Process Variables)
62-297.310(6)(a)	All Units (Permanent Test Facilities-general)

62-297.310(6)(c)	All Units (Sampling Ports)
62-297.310(6)(d)	All Units (Work Platforms)
62-297.310(6)(e)	All Units (Access)
62-297.310(6)(f)	All Units (Electrical Power)
62-297.310(6)(g)	All Units (Equipment Support)
62-297.310(7)(a)1.	Applies mainly to CTs/Diesels
62-297.310(7)(a)2.	FFSG excess emissions
62-297.310(7)(a)3.	Permit Renewal Test Required
62-297.310(7)(a)4.a	Annual Test
62-297.310(7)(a)5.	PM exemption if <400 hrs/yr
62-297.310(7)(a)6.	PM FFSG semi annual test required if >200 hrs/yr
62-297.310(7)(a)7.	PM quarterly monitoring if >100 hrs/yr
62-297.310(7)(a)9.	FDEP Notification - 15 days
62-297.310(7)(c)	Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	Test Reports

Federal Rules:

NSPS Subpart GG:	
40 CFR 60.332(a)(1)	NO_x for Electric Utility CTs
40 CFR 60.332(a)(3)	NO_x for Electric Utility CTs
40 CFR 60.333	SO_2 limits
40 CFR 60.334	Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	Test Methods

NSPS General Requirements:	
40 CFR 60.7(a)(1)	Notification of Construction
40 CFR 60.7(a)(2)	Notification of Initial Start-Up
40 CFR 60.7(a)(3)	Notification of Actual Start-Up
40 CFR 60.7(a)(4)	Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	Notification of CEM Demonstration
40 CFR 60.7(b)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(c)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(d)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	Notification and Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	Performance Test Requirements
40 CFR 60.8(b)	Performance Test Notification
40 CFR 60.8(c)	Performance Tests (representative conditions)
40 CFR 60.8(e)	Provide Stack Sampling Facilities

40 CFR 60.8(f)	Test Runs
40 CFR 60.11(a)	Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	Circumvention
40 CFR 60.13(a)	Monitoring (Appendix B; Appendix F)

40 CFR 60.13(c)	Monitoring (Opacity COMS)
40 CFR 60.13(d)(1)	Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(d)(2)	Monitoring (COMS; span, system check)
40 CFR 60.13(e)	Monitoring (frequency of operation)
40 CFR 60.13(f)	Monitoring (frequency of operation)
40 CFR 60.13(h)	Monitoring (COMS; data requirements)

Acid Rain-Permits:

40 CFR 72.9(a)	Permit Requirements
40 CFR 72.9(b)	Monitoring Requirements
40 CFR 72.9(c)(1)	SO_2 Allowances-hold allowances
40 CFR 72.9(c)(2)	SO_2 Allowances-violation
40 CFR 72.9(c)(3)(iii)	SO_2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4)	SO_2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	SO_2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(d)	NO_x Requirements
40 CFR 72.9(e)	Excess Emission Requirements
40 CFR 72.9(f)	Recordkeeping and Reporting
40 CFR 72.9(g)	Liability
40 CFR 72.20(a)	Designated Representative; required
40 CFR 72.20(b)	Designated Representative; legally binding
40 CFR 72.20(c)	Designated Representative; certification requirements
40 CFR 72.21	Submissions
40 CFR 72.22	Alternate Designated Representative
40 CFR 72.23	Changing representatives; owners
40 CFR 72.24	Certificate of representation
40 CFR 72.30(a)	Requirements to Apply (operate)
40 CFR 72.30(b)(2)	Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	Requirements to Apply (submittal requirements)
40 CFR 72.31	Information Requirements; Acid Rain Applications
40 CFR 72.32	Permit Application Shield
40 CFR 72.33(b)	Dispatch System ID; unit/system ID
40 CFR 72.33(c)	Dispatch System ID; ID requirements
40 CFR 72.33(d)	Dispatch System ID; ID change
40 CFR 72.40(a)	General; compliance plan
40 CFR 72.40(b)	General; multi-unit compliance options
40 CFR 72.40(c)	General; conditional approval
40 CFR 72.40(d)	General; termination of compliance options
40 CFR 72.51	Permit Shield
40 CFR 72.90	Annual Compliance Certification

Allowances:

40 CFR 73.33(a),(c)	Authorized account representative
40 CFR 73.35(c)(1)	Compliance: ID of allowances by serial number

Monitoring Part 75:

40 CFR 75.4	Compliance Dates;

40 CFR 75.5	Prohibitions
40 CFR 75.10(a)(1)	Primary Measurement; SO_2;
40 CFR 75.10(a)(2)	Primary Measurement; NO_x;
40 CFR 75.10(a)(3)(iii)	Primary Measurement; CO_2; O_2 monitor
40 CFR 75.10(b)	Primary Measurement; Performance Requirements
40 CFR 75.10(c)	Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(e)	Primary Measurement; Optional Backup Monitor
40 CFR 75.10(f)	Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	Primary Measurement; Minimum Recording
40 CFR 75.11(d)	SO_2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	SO_2 Monitoring; Gaseous firing
40 CFR 75.12(a)	NO_x Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(b)	NO_x Monitoring; Determination of NO_x emission rate; Appendix F
40 CFR 75.13(b)	CO_2 Monitoring; Appendix G
40 CFR 75.13(c)	CO_2 Monitoring; Appendix F
40 CFR 75.14(c)	Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	Certification Procedures (if recertification necessary)
40 CFR 75.20(d)	Recertification Backup/portable monitor
40 CFR 75.20(f)	Alternate Monitoring system
40 CFR 75.21(a)	QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	QA/QC; Calibration Gases
40 CFR 75.21(d)	QA/QC; Notification of RATA
40 CFR 75.21(e)	QA/QC; Audits
40 CFR 75.21(f)	QA/QC; CEMS (Effective 7/17/96-12/31/96)
40 CFR 75.22	Reference Methods
40 CFR 75.24	Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	General Missing Data Procedures; NO_x
40 CFR 75.30(a)(4)	General Missing Data Procedures; SO_2
40 CFR 75.30(b)	General Missing Data Procedures; certified backup monitor
40 CFR 75.30(c)	General Missing Data Procedures; certified backup monitor
40 CFR 75.30(d)	General Missing Data Procedures; SO_2 (optional before 1/1/97)
40 CFR 75.30(e)	General Missing Data Procedures; bypass/multiple stacks
40 CFR 75.31	Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	Monitoring Data Availability for Missing Data
40 CFR 75.33	Standard Missing Data Procedures
40 CFR 75.36	Missing Data for Heat Input
40 CFR 75.40	Alternate Monitoring Systems-General
40 CFR 75.41	Alternate Monitoring Systems-Precision Criteria
40 CFR 75.42	Alternate Monitoring Systems-Reliability Criteria
40 CFR 75.43	Alternate Monitoring Systems-Accessibility Criteria
40 CFR 75.44	Alternate Monitoring Systems-Timeliness Criteria
40 CFR 75.45	Alternate Monitoring Systems-Daily QA
40 CFR 75.46	Alternate Monitoring Systems-Missing data
40 CFR 75.47	Alternate Monitoring Systems-Criteria for Class
40 CFR 75.48	Alternate Monitoring Systems-Petition
40 CFR 75.53	Monitoring Plan; revisions

40 CFR 75.54(a)	Recordkeeping-general
40 CFR 75.54(b)	Recordkeeping-operating parameter
40 CFR 75.54(c)	Recordkeeping-SO_2
40 CFR 75.54(d)	Recordkeeping- NO_x
40 CFR 75.54(e)	Recordkeeping-CO_2
40 CFR 75.54(f)	Recordkeeping-Opacity
40 CFR 75.55(c)	General Recordkeeping (Specific Situations)
40 CFR 75.55(e)	General Recordkeeping (Specific Situations)
40 CFR 75.56	Certification; QA/QC Provisions
40 CFR 75.60	Reporting Requirements-General
40 CFR 75.61	Reporting Requirements-Notification cert/recertification
40 CFR 75.62	Reporting Requirements-Monitoring Plan
40 CFR 75.63	Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.66	Petitions to the Administrator (if required)
Appendix A-1	Installation and Measurement Locations
Appendix A-2.	Equipment Specifications
Appendix A-3.	Performance Specifications
Appendix A-4.	Data Handling and Acquisition Systems
Appendix A-5.	Calibration Gases
Appendix A-6.	Certification Tests and Procedures
Appendix A-7.	Calculations
Appendix B	QA/QC Procedures
Appendix C-1.	Missing Data; SO_2/ NO_x for controlled sources
Appendix C-2.	Missing Data; Load-Based Procedure; NO_x & flow
Appendix D	Optional SO_2; Oil-/gas-fired units
Appendix F	Conversion Procedures
Appendix H	Traceability Protocol

Acid Rain Program-Excess Emissions (these are future requirements):

40 CFR 77.3	Offset Plans (future)
40 CFR 77.5(b)	Deductions of Allowances (future)
40 CFR 77.6	Excess Emissions Penalties (SO_2 and NO_x; future)

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA CT/HRSG. Designated as Unit 8B. This is an existing emission unit.

4. Emissions Unit Identification Number:
ID:

[ ] No ID
[X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a GE Frame 7FA CT/HRSG operating in simple and combined cycle mode (see PSD Report).

Emissions Unit Control Equipment

1.	Control Equipment/Method Description (Limit to 200 characters per device or method): **Natural Gas Firing** • **Simple Cycle - Dry Low NO_X combustion** • **Combined Cycle - SCR** **Distillate Fuel Oil Firing** • **Water Injection** • **Combined Cycle - SCR**
2.	Control Device or Method Code(s): **25, 28, 65**

Emissions Unit Details

1.	Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**	
2.	Generator Nameplate Rating:	**172** MW	
3.	Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		°F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			1,600	mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
		hours/day		days/week
		weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,811 MMBtu/hr (ISO-LHV) and 180 MW; Higher power modes – gas is 1,680 MMBtu/hr and 182 MW. The maximum heat input for the HRSG duct burners is 550 MMBtu/hr.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PMR8-EU1-D for operational requirements.
See PSD Report for permitting requirements.

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through the HRSG stack during combined cycle operation and through the bypass stack during simple cycle operation.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **HRSG-120 / Bypass-80** feet	7. Exit Diameter: **HRSG-19 / Bypass-22** feet
8. Exit Temperature: **202 / 1,116** °F	9. Actual Volumetric Flow Rate: **1,004,150 / 2,389,462** acfm	10. Water Vapor: **8.4** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Stack parameters for ISO operating condition firing natural gas above; for oil 295 / 1,098°F and 1,193,859 / 2,735,300 ACFM; HPM 205 / 1,130°F and 1,014,759 / 2,426,858 (combined cycle / simple cycle).

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **14**	5. Maximum Annual Rate: **7,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV of 18,300 Btu/lb, ISO conditions, 500 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.68**	5. Maximum Annual Rate: **14,754**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 8,760 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025, 028	065	EL
CO			EL
VOC			EL
PM_{10}			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** b/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if > 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during gas firing - all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **103.1** lb/hour **70.0** tons/year

4. Synthetically Limited? [X]

5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor:
   Reference: **GE, 2000; Golder**

7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

   See PSD Report, Section 2.0; and Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **See Comment**

4. Equivalent Allowable Emissions: **13.3** lb/hour **70.0** tons/year

5. Method of Compliance (limit to 60 characters):

   Fuel Sampling

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Requested allowable emissions and units: Pipeline Natural Gas. natural gas firing CT with duct firing, 1 gram/100 cf - 35°F, 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **10.6** lb/hour **92.2** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **10.6** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions **1** of **3**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 42 ppmvd, CC - 12 ppmvd**	4. Equivalent Allowable Emissions: **333.8 / 95.4** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 9 ppmvd, CC - 2.5 ppmvd**	4. Equivalent Allowable Emissions: **61.3 / 24.2** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ____ to ____ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **105.1** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. HPM firing; 35°F; 100% load; TPY @ 59°F, 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd - Baseload**	4. Equivalent Allowable Emissions: **68.1** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **28.6** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **89.0** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **HPM and duct firing; 80°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A. VOC emissions exclusive of background VOC concentrations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**	4. Equivalent Allowable Emissions: **6.0** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ____ to ____ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6.2 ppmvd, includes CT and duct burner**	4. Equivalent Allowable Emissions: **11.69** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvw**	4. Equivalent Allowable Emissions: **2.8** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: HPM firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if >400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75 have been installed for this unit. Information previously submitted to DEP.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **DEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD Report [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD Report [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [ ] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [ ] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [ ] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID:________

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA CT/HRSG. Designated as Unit 8C.

4. Emissions Unit Identification Number:
ID:
[ ] No ID
[X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a GE Frame 7FA CT/HRSG operating in simple and combined cycle mode (see PSD Report).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Natural Gas Firing • Simple Cycle - Dry Low NO_X combustion • Combined Cycle - SCR Distillate Fuel Oil Firing • Water Injection • Combined Cycle - SCR
2. Control Device or Method Code(s): **25, 28, 65**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**	
2. Generator Nameplate Rating:	**172** MW	
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		1,600	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			

Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,811 MMBtu/hr (ISO-LHV) and 180 MW; Higher power modes – gas is 1,680 MMBtu/hr and 182 MW. The maximum heat input for the HRSG duct burners is 550 MMBtu/hr.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PMR8-EU1-D for operational requirements.
See PSD Report for permitting requirements.

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through the HRSG stack during combined cycle operation and through the bypass stack during simple cycle operation.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **HRSG-120 / Bypass-80** feet	7. Exit Diameter: **HRSG-19 / Bypass-22** feet
8. Exit Temperature: **202 / 1,116** °F	9. Actual Volumetric Flow Rate: **1,004,150 / 2,389,462** acfm	10. Water Vapor: **8.4** %

11. Maximum Dry Standard Flow Rate: **800,000** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Stack parameters for ISO operating condition firing natural gas above; for oil 295 / 1,098°F and 1,193,859 / 2,735,300 ACFM; HPM 205 / 1,130°F and 1,014,759 / 2,426,858 (combined cycle / simple cycle).

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **14**	5. Maximum Annual Rate: **7,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV of 18,300 Btu/lb, ISO conditions, 500 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.68**	5. Maximum Annual Rate: **14,754**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 8,760 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025, 028	065	EL
CO			EL
VOC			EL
PM_{10}			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** b/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if > 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ____ to ____ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during gas firing - all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **103.1** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **103.1** lb/hour **70.0** tons/year

4. Synthetically Limited? [X]

5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor: Reference: **GE, 2000; Golder**

7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

See PSD Report, Section 2.0; and Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Emission Factor: 2 grains S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **See Comment**

4. Equivalent Allowable Emissions: **13.3** lb/hour **70.0** tons/year

5. Method of Compliance (limit to 60 characters):

Fuel Sampling

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Requested allowable emissions and units: Pipeline Natural Gas. natural gas firing CT with duct firing, 1 gram/100 cf - 35°F, 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **10.6** lb/hour **70** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 42 ppmvd, CC - 12 ppmvd**	4. Equivalent Allowable Emissions: **333.8 / 95.4** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 9 ppmvd, CC - 2.5 ppmvd**	4. Equivalent Allowable Emissions: **61.3 / 24.2** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **105.1** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. HPM firing; 35°F; 100% load; TPY @ 59°F, 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd - Baseload**	4. Equivalent Allowable Emissions: **68.1** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **28.6** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **89.0** lb/hour **205.4** tons/year

4. Synthetically Limited? [X]

5. Range of Estimated Fugitive Emissions:
[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor:
Reference: **GE, 2000; Golder**

7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

See PSD Report, Section 2.0; and Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Lb/hr based on oil firing; 100% load; 35°F. Tons/yr see PSD Report, Section 2.0, Table 2-5; and Appendix A.

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **15 ppmvd**

4. Equivalent Allowable Emissions: **89.0** lb/hour **205.4** tons/year

5. Method of Compliance (limit to 60 characters):

EPA Method 10; high load

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

HPM and duct firing; 80°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A. VOC emissions exclusive of background VOC concentrations.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**	4. Equivalent Allowable Emissions: **6.0** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6.2 ppmvd, includes CT and duct burner**	4. Equivalent Allowable Emissions: **11.69** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 ppmvw**	4. Equivalent Allowable Emissions: **2.8** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: HPM firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if >400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75 have been installed for this unit. Information previously submitted to DEP.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **DEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1.	Process Flow Diagram [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested
2.	Fuel Analysis or Specification [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested
3.	Detailed Description of Control Equipment [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested
4.	Description of Stack Sampling Facilities [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable
6.	Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7.	Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8.	Supplemental Information for Construction Permit Application [X] Attached, Document ID: **PSD Report** [ ] Not Applicable
9.	Other Information Required by Rule or Statute [X] Attached, Document ID: **PSD Report** [ ] Not Applicable
10.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:_______ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:_______ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:_______ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:_______ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:_______ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:_______ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:_______ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:_______ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:_______ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:_______ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[**X**] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[**X**] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
GE Frame 7FA CT/HRSG. Designated as Unit 8D.

4. Emissions Unit Identification Number: [ ] No ID
ID: [**X**] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[**X**]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a GE Frame 7FA CT/HRSG operating in simple and combined cycle mode (see PSD Report).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Natural Gas Firing** • **Simple Cycle - Dry Low NO_X combustion** • **Combined Cycle - SCR** **Distillate Fuel Oil Firing** • **Water Injection** • **Combined Cycle - SCR**	
2. Control Device or Method Code(s): **25, 28, 65**	

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**
2. Generator Nameplate Rating: **172** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			**1,600**	mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:		hours/day		days/week
		weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,811 MMBtu/hr (ISO-LHV) and 180 MW; Higher power modes – gas is 1,680 MMBtu/hr and 182 MW. The maximum heat input for the HRSG duct burners is 550 MMBtu/hr.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PMR8-EU1-D for operational requirements.
See PSD Report for permitting requirements.

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through the HRSG stack during combined cycle operation and through the bypass stack during simple cycle operation.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **HRSG-120 / Bypass-80** feet	7. Exit Diameter: **HRSG-19 / Bypass-22** feet
8. Exit Temperature: **202 / 1,116** °F	9. Actual Volumetric Flow Rate: **1,004,150 / 2,389,462** acfm	10. Water Vapor: **8.4** %
11. Maximum Dry Standard Flow Rate: **800,000** dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: **17** East (km): **543.1** North (km): **2992.9**		
14. Emission Point Comment (limit to 200 characters): **Stack parameters for ISO operating condition firing natural gas above; for oil 295 / 1,098°F and 1,193,859 / 2,735,300 ACFM; HPM 205 / 1,130°F and 1,014,759 / 2,426,858 (combined cycle / simple cycle).**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate: **14**	5. Maximum Annual Rate: **7,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Million Btu per SCC Unit = 129.9 (rounded to 130). Based on 7.1 lb/gal; LHV of 18,300 Btu/lb, ISO conditions, 500 hrs/yr operation.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.68**	5. Maximum Annual Rate: **14,754**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Based on 950 Btu/cf (LHV); ISO conditions and 8,760 hrs/yr operation.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	025, 028	065	EL
CO			EL
VOC			EL
PM_{10}			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** b/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Methods 5 or 17; if > 400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during gas firing - all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **103.1** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **GE, 2000; Golder**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   See PSD Report, Section 2.0; and Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Emission Factor: 2 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**
4. Equivalent Allowable Emissions: **13.3** lb/hour **70.0** tons/year
5. Method of Compliance (limit to 60 characters):

   Fuel Sampling

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Requested allowable emissions and units: Pipeline Natural Gas. natural gas firing CT with duct firing, 1 gram/100 cf - 35°F, 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.1** lb/hour **70.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 2 grain S per 100 CF gas; 0.05% S oil; lb/hr based on oil firing at 100% load and 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Comment**	4. Equivalent Allowable Emissions: **10.6** lb/hour **70** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested allowable emissions and units: Pipeline Natural Gas. HPM firing, 1 gram/100 cf - 35°F, 100% load; 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 42 ppmvd, CC - 12 ppmvd**	4. Equivalent Allowable Emissions: **333.8 / 95.4** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions is at 15% O_2-100% load. Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **SC - 9 ppmvd, CC - 2.5 ppmvd**	4. Equivalent Allowable Emissions: **61.3 / 24.2** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **SC-333.8 / CC-95.4** lb/hour **169.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **105.1** lb/hour **169.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 24-Hour Block Average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units is at 15% O_2-100% load. HPM firing; 35°F; 100% load; TPY @ 59°F, 60 hrs/yr. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd - Baseload**	4. Equivalent Allowable Emissions: **68.1** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ____ to ____ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **28.6** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.0** lb/hour **205.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. Tons/yr see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd**	4. Equivalent Allowable Emissions: **89.0** lb/hour **205.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; high load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **HPM and duct firing; 80°F; 100% load; TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**
2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **GE, 2000; Golder**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   See PSD Report, Section 2.0; and Appendix A. VOC emissions exclusive of background VOC concentrations.
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvw**
4. Equivalent Allowable Emissions: **6.0** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters):

   EPA Method 25A; high and low load
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Oil firing; max @ 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.69** lb/hour **27.6** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **6.2 ppmvd, includes CT and duct burner**	4. Equivalent Allowable Emissions: **11.69** lb/hour **27.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; high and low load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Additional requested allowable emissions and units: Gas firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **11.69** lb/hour **27.6** tons/year

4. Synthetically Limited? [X]

5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor:
   Reference: **GE, 2000; Golder**

7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

   See PSD Report, Section 2.0; and Appendix A.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Lb/hr based on oil firing; 100% load; 35°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **1.5 ppmvw**

4. Equivalent Allowable Emissions: **2.8** lb/hour **27.6** tons/year

5. Method of Compliance (limit to 60 characters):

   EPA Method 25A; high and low load

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Additional requested allowable emissions and units: HPM firing; 35°F; 100% load; TPY see PSD Report, Section 2.0, Table 2.5; and Appendix A.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **37.8 lb/hr**	4. Equivalent Allowable Emissions: **37.8** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5 or 17 if >400 hours**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions during oil firing - all loads; 500 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **37.8** lb/hour **63.4** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. TPY see PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **17.2 lb/hr**	4. Equivalent Allowable Emissions: **17.2** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 8,760 hrs/yr. See PSD Report, Section 2.0, Table 2-5; and Appendix A.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_x CEM proposed to meet requirements of 40 CFR Part 75 have been installed for this unit. Information previously submitted to DEP.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **DEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: **Not yet determined** Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR Part 60; subpart GG; 60.334.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested	
2. Fuel Analysis or Specification [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested	
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable	
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: **PSD Report** [ ] Not Applicable	
9. Other Information Required by Rule or Statute [X] Attached, Document ID: **PSD Report** [ ] Not Applicable	
10. Supplemental Requirements Comment:	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:_______ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:_______ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:_______ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:_______ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:_______ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:_______ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:_______ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:_______ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:_______ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:_______ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[X] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Natural Gas Heaters

4. Emissions Unit Identification Number: [ ] No ID
ID: [X] ID Unknown

5. Emissions Unit Status Code: **C**	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is Natural Gas Heaters for the GE Frame 7FA combustion turbines operating in simple cycle mode (see PSD Report).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_x combustion - Natural gas firing**
2. Control Device or Method Code(s): **25**

Emissions Unit Details

1. Package Unit: Manufacturer: **Gas Tech or Equivalent**	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1.	Maximum Heat Input Rate:		23.71	mmBtu/hr
2.	Maximum Incineration Rate:	lb/hr		tons/day
3.	Maximum Process or Throughput Rate:			
4.	Maximum Production Rate:			
5.	Requested Maximum Operating Schedule:			
		hours/day		days/week
		weeks/year	3,390	hours/year
6.	Operating Capacity/Schedule Comment (limit to 200 characters): Maximum heat input per unit when natural gas firing (HHV).			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See PSD Report for permitting requirements	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through a single stack.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **30** feet	7. Exit Diameter: **1** foot
8. Exit Temperature: **700** °F	9. Actual Volumetric Flow Rate: **11,736** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Each Heater will have one stack.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas < 100 MMBtu/hr**		
2. Source Classification Code (SCC): **10100602**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **0.023**	5. Maximum Annual Rate: **311.9**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1020**
10. Segment Comment (limit to 200 characters): **Maximum hourly based on 1020 Btu/cf (HHV) for each heater; maximum annual based on 3,390 hrs/yr operation for 4 heaters.**		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_X	026		EL
CO			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_X**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.36** lb/hour **16** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GasTech, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on one heater. TPY based on 3,390 hrs/yr for 4 heaters.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **2.36** b/hour **16** tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See PSD Report, Section 2.0.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.79** lb/hour **12** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GasTech, 2000; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on one heater. TPY based on 3,390 and 4 heaters.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.075 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See PSD Report, Section 2.0.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Maximum for gas firing. Rule 62-296.320 allows 20% opacity**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ______ of______

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **DEP Rule 62-201.700(1), Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ______ of ______

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: **PSD Report** [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: **PSD Report** [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[X] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Cooling Tower

4. Emissions Unit Identification Number: [ ] No ID
ID: [X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit is a 18 cell mechanical draft cooling tower (see PSD Report).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Drift Eliminators**	
2. Control Device or Method Code(s):	

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	24 hours/day		**7** days/week
	52 weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See PSD Report for permitting requirements	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See PSD Report**

2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Exhausts through 18 stacks.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **45** feet	7. Exit Diameter: **38** foot
8. Exit Temperature: **90** °F	9. Actual Volumetric Flow Rate: **1,386,055** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm

12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **543.1** North (km): **2992.9**

14. Emission Point Comment (limit to 200 characters):

Volume is per cell.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM_{10}			EL
PM			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.65** lb/hour **20.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **FPL, 2001; Golder, 2002**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **4.65** lb/hour	4. Equivalent Allowable Emissions: **4.65** b/hour **20.4** tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **15.51** lb/hour **67.9** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **FPL, 2001; Golder, 2002**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See PSD Report, Section 2.0; and Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15.51** lb/hr	4. Equivalent Allowable Emissions: **15.51** lb/hour **67.9** tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested	
2. Fuel Analysis or Specification [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [X] Attached, Document ID: **PSD Report** [ ] Not Applicable [ ] Waiver Requested	
5. Compliance Test Report [ ] Attached, Document ID:_______ [ ] Previously submitted, Date:____________ [X] Not Applicable	
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested	
7. Operation and Maintenance Plan [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested	
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: **PSD Report** [ ] Not Applicable	
9. Other Information Required by Rule or Statute [X] Attached, Document ID: **PSD Report** [ ] Not Applicable	
10. Supplemental Requirements Comment:	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

PSD REPORT

1.0 INTRODUCTION

Florida Power & Light Company (FPL), proposes to license, construct, and operate a nominal 1,150-megawatt (MW) combined cycle unit, at the existing Martin Power Plant located in unincorporated Martin County, Florida (Figure 1-1). Martin Unit 8 will be located south of the existing Units 3 and 4 on approximately 44-acres of the 11,300–acre Martin Plant site. The combined cycle unit will consist of four General Electric (GE) 7FA combustion turbines (CTs) and associated electric generators, four heat recovery steam generators (HRSGs) and single steam turbine with associated electric generator. This is referred to as a "4 on 1" combined cycle unit. The two existing simple cycle CTs, referred to as Units 8A and 8B, will be equipped with HRSGs to produce steam. The two new CTs with associated HRSGs, to be referred to as Units 8C and 8D, will be added along with the steam turbine/electric generator. A mechanical draft cooling tower may be installed and is an option for the Project. Together these facilities are referred to as the "Project".

Martin Units 8A and 8B are currently authorized to operate up to a heat input equivalent of 3,390 hours per year in simple cycle mode that includes a heat input equivalent of 500 hours of year operation using light distillate oil [Florida Department of Environmental Protection (FDEP) Permit No. 0850001-008-AC; PSD-FL-286]. As part of the Martin Unit 8 Project, these units will be converted to combined cycle with substantial emission reductions for NO_x. Simple cycle operation for these units will continue until they can be integrated into combined cycle configuration. The new CTs (i.e., Unit 8C and 8D) will be identical to the existing CTs and are proposed to operate in simple cycle mode during the first year of operation. When combined cycle is complete, the option for limited simple cycle operation is being proposed.

The CTs will use dry low-nitrogen oxide (DLN) combustion technology when operating on natural gas and water injection for nitrogen oxide (NO_x) control when operating on light distillate fuel oil and power augmentation. Each CT/HRSG will be installed with selective catalytic reduction (SCR) to further reduce emissions of NO_x. Each CT/HRSG will also have the capability of operating in simple cycle mode. Each HRSG will be equipped with duct burners that will fire only natural gas with a maximum heat input of 550 million British thermal units per hour (MMBtu/hr). The primary fuel for the CTs will be natural gas with distillate fuel oil used as backup fuel. Fuel oil will contain a maximum sulfur content of 0.05 percent.

The permitting of the Project requires an Air Construction Permit and PSD review. PSD review requires air quality assessments for determining the facility's compliance with state and federal new source review (NSR) regulations, including addressing applicable PSD and nonattainment review requirements. The critical aspects of these assessments include the air quality impact analyses performed using appropriate air dispersion models and the Best Available Control Technology (BACT) analyses performed to evaluate the selected emission control technology.

The proposed Project will be a modification to an existing major air pollution source that will result in net increases in air emissions. The U.S. Environmental Protection Agency (EPA) has implemented regulations requiring a PSD review for new or modified sources that increase air emissions above certain threshold amounts. Because the threshold amounts for a modification will be exceeded by the Project, the Project is subject to PSD review. PSD regulations are promulgated under 40 Code of Federal Regulations (CFR) Part 52.21 and implemented by the FDEP. Florida's PSD regulations are codified in Rules 62-212.400, Florida Administrative Code (F.A.C.) and have been delegated by EPA to FDEP. These Florida PSD regulations incorporate the requirements of EPA's PSD regulations.

Based on the emissions from the proposed facility, PSD review is required for each of the following regulated pollutants:

- Particulate matter (PM) as total suspended particulate matter (TSP),
- Particulate matter with aerodynamic diameter of 10 microns or less (PM_{10}),
- Nitrogen dioxide (NO_2),
- Sulfur dioxide (SO_2),
- Carbon monoxide (CO),
- Volatile organic compounds (VOCs), and
- Sulfuric acid mist.

Martin County has been designated as an attainment area for all criteria pollutants [i.e., attainment: (O_3), PM_{10}, SO_2, CO, and NO_2; unclassifiable: lead] and is a PSD Class II area for PM_{10}, SO_2, and NO_2; therefore, the PSD review will follow regulations pertaining to such designations.

The air permit application is divided into seven major sections:

- Section 2.0 presents a description of the Project, including air emissions and stack parameters.
- Section 3.0 provides a review of the PSD and nonattainment requirements applicable to the Project.
- Section 4.0 includes the control technology review with discussions on BACT.
- Section 5.0 discusses the ambient air monitoring analysis (pre-construction monitoring) required by PSD regulations.
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the proposed facility with ambient air quality standards (AAQS), and PSD increments.
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility.

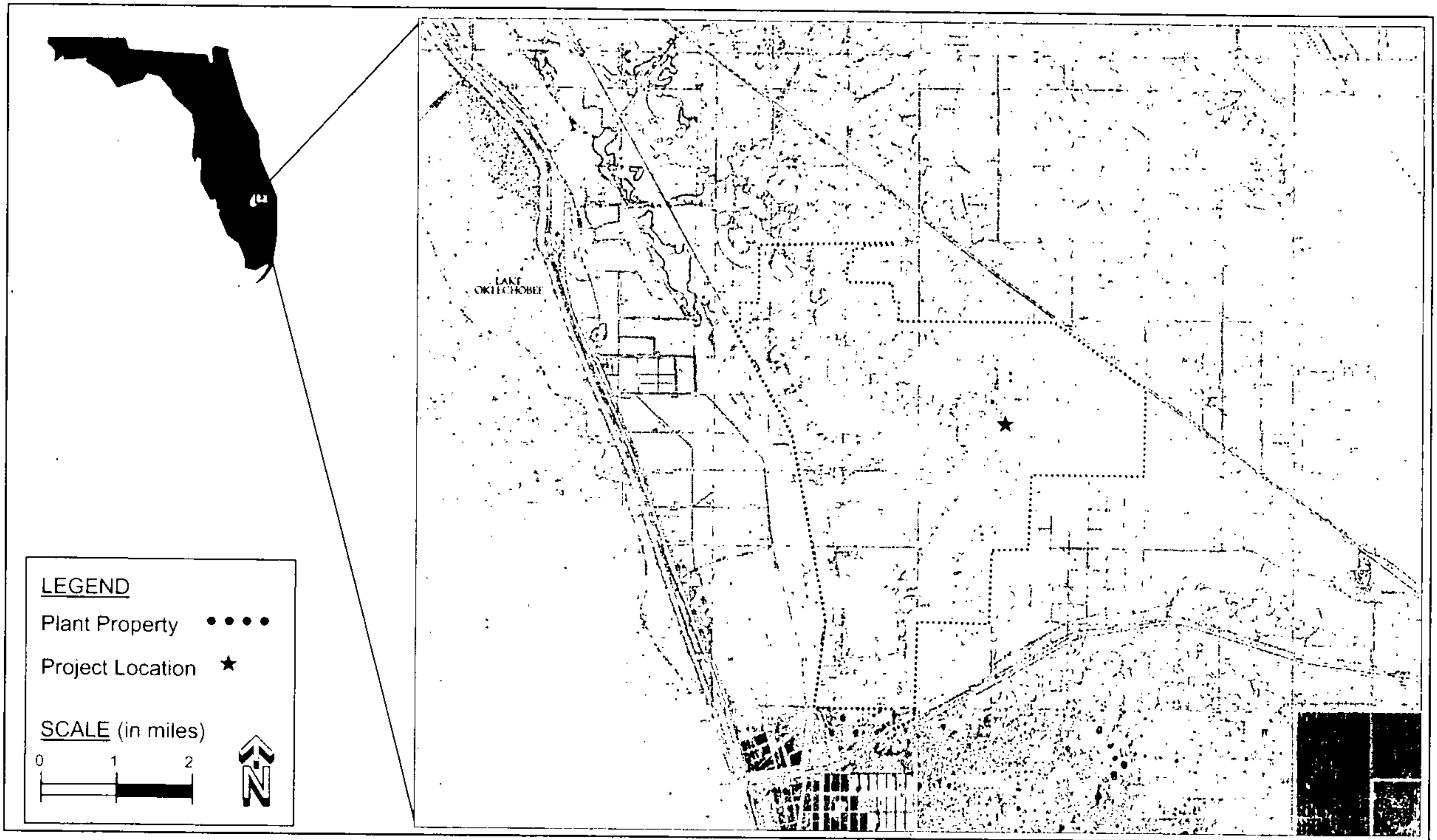

Figure 1-1. FPL Martin Plant Site Location

Source: Bechtel Power Corporation, 1989; Golder, 2002.

FPL

Martin Unit 8

2.0 PROJECT DESCRIPTION

2.1 SITE DESCRIPTION

The Martin Plant site (shown in Figure 1-1) consists of 11,300 acres that is wholly owned by FPL. The site is comprised of a 6,800-acre cooling pond and approximately 400 acres for the existing power facilities. The remaining area consists of undeveloped or agricultural land. There is minimal industrial, commercial, and residential development within a 5-kilometer (km) radius of the site. The plant elevation will be approximately 32 feet above sea level. The terrain surrounding the site is flat.

Natural gas is supplied to the Martin Plant by two lateral pipelines connected to the Florida Gas Transmission (FGT) natural gas pipeline located to the east of the site. A segment of the new pipeline will be located north and east of the Martin Plant, which may eventually provide gas to the site.

2.2 POWER PLANT

The proposed facility will be configured as a 4 on 1 combined unit for base load service. The combined cycle unit will consist of four GE Frame 7FA CTs with an associated HRSGs and a steam turbine-generator. The CTs will use DLN combustion technology (when firing natural gas) and water injection (when firing distillate oil) to minimize NO_x formation. SCR will be installed in each HRSG to further reduce emissions of NO_x. Natural gas will be used as the primary fuel, and light distillate fuel oil will be used as an alternate fuel. Fuel oil usage will be limited to the equivalent of 500 hours per year (hr/yr) at full load. Each HRSG will be equipped with duct burners with a maximum heat input of 550 MMBtu/hr. Duct firing will be limited to an equivalent heat input of 550 MMBtu/hr for 2,880 hours or 1,584,000 million Btu/year per CT/HRSG.

Plant performance for the GE 7FA CTs was developed for natural gas and oil at 50-, 75-, and 100-percent load and 35 degrees Fahrenheit (°F), 59°F, 75°F, and 95°F ambient dry bulb temperatures. Nominal part load percentages herein are relative to 100-percent load without evaporative cooling. Data were also developed for higher power modes (HPM) that include peak operation and power augmentation for the range of operating loads and temperatures. In addition, the CTs can operate with power augmentation (data are provided for ambient temperature of 80°F). More detailed discussions on these operations are presented in Section 2.3.

The CTs will be capable of operating from 50- to 100-percent base load. The efficiency of the CTs decreases at part load. As a result, the economic incentive is to dispatch the plant to keep the units operating as near to base load as possible.

Natural gas will be transported to the site via pipeline, and fuel oil will be trucked to the site. The distillate fuel oil, which will have a maximum sulfur content of 0.05 percent, will be stored onsite in two aboveground storage tanks, sized to hold approximately 50,000 barrels (2 million gallons). One of these tanks is existing, while an additional aboveground storage tank will be installed. The second tank was previously approved during the permitting of Units 3 and 4 and Units 8A and 8B.

Air emissions control will consist of using state-of-the-art DLN burners in the CTs when firing natural gas. Each GE Frame 7FA will be equipped with the GE DLN-2.6 combustion system that regulates the distribution of fuel delivery to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion system fuel nozzle is regulated to maintain unit load and minimize turbine emissions. The DLN-2.6 combustion system consists of six fuel nozzles per combustion can, with each operating as a fully premixed combustor. Of the six nozzles, five are located radially and one is in the center. The fuel system is fully automated and sequences the DLN-2.6 combustion system through a number of staging modes prior to reaching full load. The GE Frame 7FA has 14 combustors per turbine. Water injection will be used for NO_x control when firing distillate fuel oil. The SO_2 emissions will be controlled by the use of low-sulfur fuels. Good combustion practices and clean fuels will also minimize potential emissions of PM, CO, VOC, and other pollutants (e.g., trace metals). These engineering and environmental designs maximize control of air emissions while minimizing economic, environmental, and energy impacts (see Section 4.0 for the BACT evaluation).

SCR reactors for Unit 8 will be located in the HRSG to provide the proper operating temperature range for the required reaction between ammonia and NO_x to achieve the proposed BACT emission rate and to assure the economical operation of the system. The NO_x is reduced by a chemical reaction with the ammonia in the presence of the catalyst. The catalyst will be provided in modules, which will be installed into a structural steel reactor housing that is incorporated into the HRSG. Ammonia is carried by a diluent and injected into the exhaust gas upstream of the catalyst modules. The reactor housing will include an internal support structure for the catalyst modules, man-access and catalyst loading openings and instrument connections for monitoring catalyst performance. The ammonia handling system will include primary and standby diluent air blowers (each sized for 100-percent capacity), ammonia flow control and measurement devices, an ammonia/air mixing chamber, distribution header(s), and an ammonia injection grid (AIG). Overall control of the system will be by the distributed control system (DCS).

Each CT will have an evaporative cooling (fogger) at the turbine air inlet that reduces the inlet air temperature and increases both the efficiency and power output at elevated ambient temperatures. This cooling system will only operate when the ambient temperature is 60°F or greater and the CTs are operating. This cooling system adds water vapor to the compressor inlet of the CTs, which increases the mass flow of air by evaporative cooling, but does not affect emissions of regulated pollutants. The CTs can operate without the evaporative coolers in service.

The first year of operation will consist of simple cycle only, including fuel heating up to 3,390 hours per year per CT. The CTs in simple cycle mode will require fuel heating for the DLN system when firing natural gas. Two of these units are existing (8A and 8B) and two more (8C and 8D) will be added. Beyond the first year of operation, fuel heating will include 1,000 hours per year per CT.

2.3 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

The estimated maximum hourly emissions and exhaust information representative of each CT/HRSG operating at base-load conditions (100-percent load), 75-percent load and 50-percent load conditions in combined cycle mode are presented in Tables 2-1 and 2-2 for natural gas and distillate oil firing, respectively. Table 2-1 also includes emissions and exhaust information for duct firing. The estimated maximum hourly emissions and exhaust information representative of the simple cycle operation at base-load conditions (100-percent load), 75-percent load, and 50-percent load conditions are presented in Tables 2-3 and 2-4 for natural gas and distillate oil firing, respectively. The data are presented for ambient temperatures of 35°F, 59°F, 75°F, and 95°F. These temperatures represent the range of ambient temperatures that the CTs are most likely to experience. The performance data for the operating conditions are given in Appendix A.

The proposed pollutant gaseous emission concentrations and PM_{10} emission rates assumed for the Project are:

Pollutant	Natural Gas	Distillate Oil
NO_x (ppmvd @ 15-percent O_2)	2.5 (CC)[a] and 9/15 (SC/SC-HPM)[a]	12 (CC)[a] and 42 (SC)[a]
CO (ppmvd)	9/15(HPM)/29.5(CC/DF)	20
VOC as CH_4 (ppmvw)	1.5	3.5
SO_x as SO_2	Calculated Based on Fuel (2.0 grains S/100 SCF)	Calculated Based on Fuel (0.05-percent sulfur)
PM_{10} (lb/hr) (dry filterable)	17.2 (CC) and 9 (SC) 11.1 (HPM)	37.8 (CC) and 17 (SC)

Note: CC = combined cycle DF = Duct firing
SC = simple cycle ppmvd = Parts per million volume, dry
lb/hr = pounds per hour ppmvw = Parts per million, volume, wet
HPM = higher power mode (peak and power augmentation)
Values for ISO conditions at base load
[a] three-hour average

The maximum short-term emission rates (lb/hr) generally occur at base load, 35°F operation, where the CT has the greatest output and greatest fuel consumption. The HPM reflects either operating with power augmentation or operating in peak mode. Power augmentation is the use of steam when firing natural gas at loads above 95 percent to increase power output. About 1.5 lb steam per lb of fuel is used in this mode of operation. The existing CTs (Unit 8A and 8B) are authorized to operate in power augmentation mode for 400 hours per year. Peak mode is achieved by slightly increasing the exhaust temperature through the automated control system by adjusting the fuel distribution between the fuel nozzles while in pre-mix mode. The existing CTs are authorized to operate 60 hours in peak mode. Both power augmentation and peak modes of operation is possible while the turbine is in combined and simple cycle mode.

Based on an ambient temperature of 59°F, the emission rates used to calculate maximum potential annual emissions for the CTs/HRSGs for regulated air pollutants are presented in Table 2-5 for the facility. To produce the maximum annual emissions, it is assumed that each CT/HRSG would operate for 7,760 hours in combined cycle mode and 1,000 hours in simple cycle mode. Of the 7,760 combined cycle hours, 3,980 hours will be firing natural gas; 2,880 hours at 100-percent load with duct firing (550 MMBtu/hr); 400 hours at 100-percent load with duct firing and steam power augmentation, or peak operations. Simple cycle operation will consist of 500 hours at 100-percent load, natural gas; and 500 hours firing distillate oil at 100-percent load. For the two new CTs, simple cycle operation was assumed for the first year of operation to be at base load with 2,890 hours firing natural gas and 500 hours firing distillate oil. After the first year, simple cycle operation for the four CTs would not exceed an aggregate equivalent of 4,000 hours per year with a maximum of 2,000 hours per year of operation on distillate oil. The proposed limit on fuel oil is 3,838,000 MMBtu per year (1,919 MMBtu/hr x 4 CTs x 500 hours.) The potential emissions are based on the 59°F ambient air condition since it represents a conservative average when the annual average temperatures are slightly higher than 70°F.

Process flow diagrams of a CT/HRSG, operating at base load conditions with a compressor inlet temperature of 59°F, are presented in Figure 2-1.

The emissions information for the two new fuel heaters are presented in Table 2-6. The emissions for the optional cooling tower is presented in Table 2-7. A summary of the maximum total potential annual emissions estimated for the Project is given in Table 2-8.

Emission factors for hazardous air pollutants (HAPs) were evaluated based on the revised AP-42 emission factors and the EPA Combustion Turbine Emissions Database. The HAP emissions are based on emission factors from the April 2000 revision of EPA's AP-42 emission factors for large stationary combustion turbines. Summaries of the emission factors and emissions for fuel oil firing and gas firing are presented in Tables A-15 through A-16.

Except for formaldehyde and toluene, the emission factors are those presented in Tables 3.1-4 and 3.1-5 of the revised AP-42 section for combustion turbines. For formaldehyde, a review of EPA's database was conducted and an emission factor was estimated based on comparisons of the turbines and emission characteristics from EPA's database to those proposed for this project. A discussion regarding this review and estimation of the formaldehyde emission factor is presented in the following section.

The recent EPA emission factor suggests formaldehyde emissions from gas turbines of 710 lb/10^{12} Btu when firing natural gas at loads greater than 80 percent and 280 lb/10^{12} Btu when firing distillate oil. The EPA suggested emission factor for all loads is 3,100 lb/10^{12} Btu. Since the proposed CTs will fire primarily natural gas, with limited oil firing, the worst-case annual emissions would be from natural gas firing.

The emission factors are not appropriate for the proposed CTs based on several factors. First, and most importantly, the data used to develop the AP-42 emission factors are not representative of the GE Frame 7FA combustion turbine. Second, a review of the data of the pertinent information in the EPA database that relates to the characteristics clearly suggests a much lower emission factor for formaldehyde. Some of the important aspects of the EPA Gas Turbine Database related to formaldehyde emissions are as follows.

- The formaldehyde emissions are from small (< 30 MW) gas turbines. The available data are from an average capacity of about 28 MW. More importantly, the median capacity, or the turbine size where an equal number of turbines are above and below that size, is about 15 MW. Data from only 8 large turbines (>30 MW) are included in the EPA database, with a maximum size of 88 MW.
- In contrast to the AP-42 emission factors for formaldehyde, which are based on an average value, the median value is substantially lower. For all loads, the median formaldehyde emission factor is about 320 $lb/10^{12}$ Btu; for turbine loads greater than 50 percent, the median emission factor is about 110 $lb/10^{12}$ Btu. Since the median emission factor is about 8 to ten times lower than the average factor, this clearly points to the large range in formaldehyde emissions and how the individual turbine combustion characteristics can influence the results. The median is a measure of the middle of the distribution and in distributions where there is symmetry about the mean, and where the mean and median coincide. However, in highly skewed distributions, as that observed for formaldehyde emissions, the median is more representative of a "truer average" since the median is not influenced by extreme values.
- There is a strong relationship between formaldehyde and CO emissions, as noted by EPA in the support document and, and as observed in the data. Gas turbines with higher CO emissions had higher observed formaldehyde emissions. An evaluation of the coincident CO and formaldehyde data indicates that formaldehyde emissions were 150 $lb/10^{12}$ Btu when the CO emissions are less than 0.1 lb/MMBtu. The CO emission guarantees for the GE Frame 7FA is about 0.016 lb/MMBtu.

At present, there are no confirmed test data of formaldehyde emissions from similar GE Frame 7FA combustion turbines.

Based on the available data, formaldehyde emissions would be within the range of 100 to 150 lb/10^{12} Btu. An emission factor of 150 lb/10^{12} Btu for formaldehyde has been used in this application.

An emission factor for toluene of 33 lb/10^{12} Btu for natural gas firing was developed from the data in the EPA Combustion Turbine Emissions Database. This factor is based on the median value for loads greater than 80 percent. Similar to formaldehyde emission factors, there are no confirmed test data of toluene emissions from a GE Frame 7FA. The recent EPA emission factor, which is based on much smaller turbines than those proposed for this project, suggests toluene emissions from gas turbines of 130 lb/10^{12} Btu when firing natural gas at loads greater than 80 percent. For all loads, the average and median EPA factors are 94 and 19 lb/10^{12} Btu, respectively. Since the median emission factor is about 4 to 5 times lower than the average factor, this clearly points to the large range in toluene emissions and how the individual turbine combustion characteristics can influence the results. The emission factor of 33 lb/10^{12} Btu is also about a factor of 4.5 times lower than that of formaldehyde, which is similar to the ratio of EPA's formaldehyde to toluene emission factors.

The emission factors for many of the other HAPs were developed by EPA in a manner similar to formaldehyde and toluene. For these HAPs, fewer data are available and are also considered not representative of state-of-the-art DLN combustion systems. The use of AP-42 emission factors for these HAPs are considered to provide conservative estimates of emissions.

An evaluation of the HAP emissions from the facility indicates that emissions are less than 25 TPY for all HAPs and less than 10 TPY for any single HAP. As shown in Tables A-15 and A-16, the maximum total emissions of HAPs are estimated to 16.7 TPY with maximum emissions of any single HAPs at 6.3 TPY. The requirements of 40 CFR 63.43 for a maximum achievable control technology (MACT) apply to the construction or reconstruction of a major source of HAPs. The proposed Project is not a major source of HAPS by itself and it is not a reconstruction of the existing facilities at the Martin Plant. Therefore, the requirements of 40 CFR 63.43 for a maximum achievable control technology are not applicable to the project.

2.4 SITE LAYOUT, STRUCTURES, AND STACK SAMPLING FACILITIES

A plot plan of the proposed Project is presented in Figure 2-2 and a profile is presented in Figure 2-3. The dimensions of the buildings and structures are presented in Section 6.0. Stack sampling facilities will be constructed in accordance to Rule 62-297.310(6) F.A.C.

2.5 EXCESS EMISSIONS

2.5.1 INTEGRATION TO COMBINED CYCLE

Prior to conversion from simple cycle to combined cycle, steam produced in the HRSG is used to clean the HRSG piping system and piping connecting each HRSG to the steam turbine. This will require the combustion turbine to operate at less than 50 percent load for periods exceeding the 2 hours allowed under FDEP rules for excess emission during start-up, shutdown and malfunction. This operation will result in emissions in excess of the emission limiting standards established for Units 8A and 8B and those being proposed for Units 8C and 8D for simple cycle mode. An excess emission allowance identical to that authorized for the FPL Fort Myers Repowering Project is requested for Martin Unit 8. The requested condition follows:

Section III, Specific Condition Number

The following NO_x excess emissions periods are applicable only at the end of construction and shall not exceed a total of 90 days per construction turbine:

- Emissions of NO_x from the combustion turbines CTs, in excess of the BACT limit established in Specific Condition 19, resulting from steam blow activities associated with bringing the heat recovery steam generators into operation shall be permitted provided that best operational practices are adhered to and that the Subpart GG NSPS limit of 75/110 ppmvd@15% O_2 is not exceeded. The period during which such excess emissions are authorized shall not exceed a total of 90 days per combustion turbine. The applicant shall record for each CT unit the periods of start-up for each operating mode. Excess emissions during the periods of startup shall be reported to the FDEP South District office within 30 days.

  [Applicant Request (FPL estimates that CT emissions will comply with the NSPS NO_x limit following initial compliance testing, but that low load operation necessary for steam blow activities prior to initial combined cycle operation will result in NO_x emissions above the BACT limit of 9 ppmvd@15 percent O_2. Excess emission of NO_x resulting from steam blows may occur intermittently over a period of up to 30 days per CT initially, followed by a period of up to 60 days of intermittent steams blows for the piping systems serving the six interconnected combined cycle units.)].

Section III, Specific Condition Number

Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which each unit configuration (i.e., simple cycle and combined cycle) will be operated, but no later than 180 days following initial operation of each unit configuration, and annually thereafter.

2.5.2 COLD START-UP IN COMBINED CYCLE

The start-up in combined cycle operation will require an excess emission allowance greater than two hours allowed under the FDEP rules. This occurs during cold start-up where the operating load of the CTs are limited by the amount of steam that can be accepted by the steam turbine. This will result in excess emissions. The same excess emission allowance is requested for Martin Unit 8 Project that was authorized for the FPL Fort Myers Repowering Project. Both Projects have similar steam turbines that receive steam during start-up (i.e., 400 MW). The proposed condition follows:

Excess Emissions Requirements:

- Excess emissions resulting from start-up, shutdown or malfunction of the *combustion turbines and heat recovery steam generators* shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to or shutdowns from combined cycle operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a start-up to combined cycle operation following a complete shutdown lasting at least 48 hours.
- Excess emissions from the combustion turbines resulting from start-up of the *steam turbines system* shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed 12 hours per cold start-up of the steam turbine system.

[Applicant Request (FPL estimates that, on average, there will be approximately 12 start-ups to combined-cycle operation per year), G.E. Combined Cycle Start-Up Curves Data and Rules 62-210.700, 62-4.130 F.A.C.)].

Table 2-1. Stack, Operating, and Emission Data for the Combustion Turbines/HRSGs and Duct Burners for Combined Cycle Operation- Natural Gas Combustion

		Operating and Emission Data [a] for Ambient Temperarure									
		Combustion Turbine/ HRSG					Combustion Turbine/ HRSG/ Duct Burner				
Parameter		35 °F	59 °F	75 °F	80 °F [b]	95 °F	35 °F	59 °F	75 °F	80 °F [b]	95 °F
CT/HRSG Stack Data (ft)											
Height		120	120	120	120	120	120	120	120	120	120
Diameter		19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
100 Percent Load											
Temperature (°F)		203	202	204	204	201	189	188	189	188	190
Velocity (ft/sec)		61.6	59.0	57.3	57.9	54.5	61.0	58.4	56.7	54.1	54.3
Maximum Hourly Emissions per Unit											
SO_2	lb/hr	10.2	9.8	9.4	9.5	8.9	13.3	12.8	12.4	12.5	11.9
PM/PM_{10}	lb/hr	11.1	11.0	10.9	10.9	10.8	17.2	17.1	17.0	17.0	16.9
NO_x	lb/hr	17.0	16.3	15.6	15.9	14.7	24.2	23.6	23.1	22.1	22.3
CO	lb/hr	28.6	27.5	26.6	45.0	25.5	72.6	71.5	70.6	89.0	69.5
VOC (as methane)	lb/hr	2.9	2.7	2.6	2.6	2.5	11.7	11.5	11.4	11.4	11.3
Sulfuric Acid Mist	lb/hr	1.02	0.98	0.94	0.95	0.89	1.63	1.59	1.55	1.56	1.49
75 Percent Load											
Temperature (°F)		187	188	189	NA	190	NA	NA	NA	NA	NA
Velocity (ft/sec)		48.4	47.1	45.9	NA	44.3	NA	NA	NA	NA	NA
Maximum Hourly Emissions per Unit											
SO_2	lb/hr	8.3	7.9	7.7	NA	7.3	NA	NA	NA	NA	NA
PM/PM_{10}	lb/hr	10.7	10.6	10.5	NA	10.5	NA	NA	NA	NA	NA
NO_x	lb/hr	13.6	13.1	12.6	NA	12.0	NA	NA	NA	NA	NA
CO	lb/hr	24.4	23.5	22.7	NA	21.7	NA	NA	NA	NA	NA
VOC (as methane)	lb/hr	2.3	2.2	2.2	NA	2.1	NA	NA	NA	NA	NA
Sulfuric Acid Mist	lb/hr	0.83	0.79	0.77	NA	0.73	NA	NA	NA	NA	NA
50 Percent Load											
Temperature (°F)		175	178	175	NA	182	NA	NA	NA	NA	NA
Velocity (ft/sec)		39.1	38.4	37.4	NA	36.9	NA	NA	NA	NA	NA
Maximum Hourly Emissions per Unit											
SO_2	lb/hr	6.6	6.4	6.2	NA	5.9	NA	NA	NA	NA	NA
PM/PM_{10}	lb/hr	10.3	10.3	10.2	NA	10.2	NA	NA	NA	NA	NA
NO_x	lb/hr	10.8	10.4	10.1	NA	9.6	NA	NA	NA	NA	NA
CO	lb/hr	20.1	19.5	19.0	NA	18.3	NA	NA	NA	NA	NA
VOC (as methane)	lb/hr	1.9	1.9	1.8	NA	1.7	NA	NA	NA	NA	NA
Sulfuric Acid Mist	lb/hr	0.66	0.64	0.62	NA	0.59	NA	NA	NA	NA	NA

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data. Duct firing is assumed for 100% operating load. No duct firing is assumed for loads less than 100%.

[b] Steam augmentation and inlet fogging.

Source: Golder, 2001.

Table 2-2. Stack, Operating, and Emission Data for the Combustion Turbines/HRSGs for Combined Cycle Operation-Distillate Fuel Oil Combustion

		Operating and Emission Data [a] for Ambient Temperarure			
		Combustion Turbine/ HRSG			
Parameter		35 °F	59 °F	75 °F	95 °F
CT/HRSG Stack Data (ft)					
Height		120	120	120	120
Diameter		19.0	19.0	19.0	19.0
100 Percent Load					
Temperature (°F)		297	295	294	294
Velocity (ft/sec)		73.6	70.2	67.7	64.5
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	103.1	98.6	94.9	89.1
PM/PM_{10}	lb/hr	37.8	36.9	36.2	35.0
NO_x	lb/hr	95.4	91.2	87.7	82.3
CO	lb/hr	68.1	64.7	62.1	58.9
VOC (as methane)	lb/hr	7.6	7.3	7.0	6.7
Lead	lb/hr	0.03	0.03	0.02	0.02
Sulfuric Acid Mist	lb/hr	10.31	9.86	9.49	8.91
75 Percent Load					
Temperature (°F)		271	274	276	278
Velocity (ft/sec)		55.6	54.3	53.3	51.4
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	82.0	78.8	76.3	72.2
PM/PM_{10}	lb/hr	33.6	32.9	32.4	31.6
NO_x	lb/hr	75.0	72.2	69.9	66.1
CO	lb/hr	53.5	51.7	50.5	48.3
VOC (as methane)	lb/hr	6.0	5.8	5.7	5.5
Lead	lb/hr	0.02	0.02	0.02	0.02
Sulfuric Acid Mist	lb/hr	8.20	7.88	7.63	7.22
50 Percent Load					
Temperature (°F)		256	259	264	268
Velocity (ft/sec)		44.6	44.0	43.5	42.6
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	64.7	62.6	60.8	57.7
PM/PM_{10}	lb/hr	30.1	29.7	29.3	28.7
NO_x	lb/hr	58.7	56.8	55.1	52.3
CO	lb/hr	44.3	43.2	42.3	41.0
VOC (as methane)	lb/hr	4.9	4.8	4.7	4.6
Lead	lb/hr	0.02	0.02	0.02	0.01
Sulfuric Acid Mist	lb/hr	6.47	6.26	6.08	5.77

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Source: Golder, 2001.

Table 2-3. Stack, Operating, and Emission Data for the Combustion Turbines for Simple Cycle Operation-
Natural Gas Combustion

		Operating and Emission Data [a] for Ambient Temperarure				
		Combustion Turbine				
Parameter		35 °F	59 °F	75 °F	80 °F [b]	95 °F
CT/Bypass Stack Data (ft)						
Height		80	80	80	80	80
Diameter		22.0	22.0	22.0	22.0	22.0
100 Percent Load						
Temperature (°F)		1,095	1,116	1,128	1,125	1,143
Velocity (ft/sec)		107.9	104.8	102.2	103 0	98.7
Maximum Hourly Emissions per Unit						
SO_2	lb/hr	10 2	9 8	9.4	9.5	8.9
PM/PM_{10}	lb/hr	9 0	9.0	9.0	9.0	9.0
NO_x	lb/hr	61.3	58.7	56.3	76.2	53.1
CO	lb/hr	28.6	27.5	26.6	45.0	25.5
VOC (as methane)	lb/hr	2.9	2.7	2.6	2.6	2.5
Sulfuric Acid Mist	lb/hr	1.02	0.98	0.94	0.95	0.89
75 Percent Load						
Temperature (°F)		1,122	1,139	1,153	NA	1,170
Velocity (ft/sec)		88.2	86.7	85.1	NA	83.0
Maximum Hourly Emissions per Unit						
SO_2	lb/hr	8.3	7.9	7.7	NA	7.3
PM/PM_{10}	lb/hr	9.0	9.0	9.0	NA	9.0
NO_x	lb/hr	48.9	47.1	45.4	NA	43.1
CO	lb/hr	24.4	23.5	22.7	NA	21.7
VOC (as methane)	lb/hr	2.3	2.2	2.2	NA	2.1
Sulfuric Acid Mist	lb/hr	0.83	0.79	0.77	NA	0.73
50 Percent Load						
Temperature (°F)		1,168	1,184	1,195	NA	1,200
Velocity (ft/sec)		74.8	73.9	72.7	NA	71 1
Maximum Hourly Emissions per Unit						
SO_2	lb/hr	6.6	6.4	6.2	NA	5.9
PM/PM_{10}	lb/hr	9.0	9.0	9.0	NA	9.0
NO_x	lb/hr	38.7	37.5	36.2	NA	34.5
CO	lb/hr	20.1	19.5	19.0	NA	18.3
VOC (as methane)	lb/hr	1.9	1.9	1.8	NA	1.7
Sulfuric Acid Mist	lb/hr	0.66	0 64	0.62	NA	0.59

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

[b] Steam augmentation and inlet fogging.

Source: Golder, 2001.

Table 2-4. Stack, Operating, and Emission Data for the Combustion Turbines for Simple Cycle Operation-Distillate Fuel Oil Combustion

		Operating and Emission Data [a] for Ambient Temperarure			
		Combustion Turbine			
Parameter		35 °F	59 °F	75 °F	95 °F
CT/Bypass Stack Data (ft)					
Height		80	80	80	80
Diameter		22.0	22.0	22.0	22.0
100 Percent Load					
Temperature (°F)		1,074	1,098	1,113	1,131
Velocity (ft/sec)		111.3	108.0	105.4	101.5
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	103.1	98.6	94.9	89.1
PM/PM_{10}	lb/hr	17.0	17.0	17.0	17.0
NO_x	lb/hr	333.8	319.2	306.8	288.2
CO	lb/hr	68.1	64.7	62.1	58.9
VOC (as methane)	lb/hr	7.6	7.3	7.0	6.7
Lead	lb/hr	0.03	0.03	0.02	0.02
Sulfuric Acid Mist	lb/hr	10.31	9.86	9.49	8.91
75 Percent Load					
Temperature (°F)		1,121	1,137	1,149	1,166
Velocity (ft/sec)		89.7	88.1	87.0	84.6
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	82.0	78.8	76.3	72.2
PM/PM_{10}	lb/hr	17.0	17.0	17.0	17.0
NO_x	lb/hr	262.6	252.6	244.5	231.2
CO	lb/hr	53.5	51.7	50.5	48.3
VOC (as methane)	lb/hr	6.0	5.8	5.7	5.5
Lead	lb/hr	0.02	0.02	0.02	0.02
Sulfuric Acid Mist	lb/hr	8.20	7.88	7.63	7.22
50 Percent Load					
Temperature (°F)		1,168	1,182	1,193	1,200
Velocity (ft/sec)		75.7	74.9	74.2	72.6
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	64.7	62.6	60.8	57.7
PM/PM_{10}	lb/hr	17.0	17.0	17.0	17.0
NO_x	lb/hr	205.6	198.9	192.9	183.2
CO	lb/hr	44.3	43.2	42.3	41.0
VOC (as methane)	lb/hr	4.9	4.8	4.7	4.6
Lead	lb/hr	0.02	0.02	0.02	0.01
Sulfuric Acid Mist	lb/hr	6.47	6.26	6.08	5.77

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Source: Golder, 2001.

Table 2-5. Summary of Maximum Potential Annual Emissions for the Combustion Turbines/HRSG for Combined and Simple Cycle Operations

Operating Scenario	Year 1			Year 2	
CC/ NG 100 % Load	0	0	0	5,380	4,480
CC/ DB /NG100 % Load	0	0	0	2,880	2,880
CC/ DB&PA/NG100 % Load	0	0	0	0	400
CC/ OIL 100 % Load	0	0	0	500	0
SC/ NG 100% Load	3,390	2,890	2,890	0	500
SC/ NG HPM100% Load	0	0	60	0	0
SC/ OIL100% Load	0	500	440	0	500
TOTAL	3,390	3,390	3,390	8,760	8,760

	Maximum Hourly Emissions (lb/hr) [a]							Maximum Emissions (tons/year) based on hours for				
	Combined Cycle (CC)				Simple Cycle (SC)			Year 1			Year 2	
Fuel:	NG	NG	NG	Oil	NG	NG	Oil					
Load:	100%	100% w/DB	100% w/DB & PA	100%	100%	HPM	100%					
Pollutant												
One Combustion Turbine												
SO_2	9.80	12.8	12 5	98.6	9.80	10 3	98 6	16.6	38 8	36 2	69.5	70.0
PM/PM_{10}	11.0	17.1	17.0	36.93	9.00	9.00	17.0	15 3	17.3	17.0	63.4	59 1
NO_x	16.3	23 6	22.1	91.20	58 7	101	319	99 4	164.6	158 0	100 6	169 4
CO	27 5	71 5	89.0	64.65	27.5	48.0	64 7	46.6	55 9	55.4	193 1	205.4
VOC (as methane)	2.74	11 5	11 4	7.28	2 74	2.75	7.28	4 6	5.8	5.6	25 8	27 6
Sulfuric Acid Mist	0.98	1.59	1.56	9 86	0 98	1 03	9.86	1 7	3.9	3.6	7.4	7.5
HAPs	0.66	0 86	0.84	2.47	0.66	0.69	2.47	1 1	1 6	1.5	3.6	3 7
Lead	0.00	0.00	0.00	0.025	0.00	0.00	0.025	0.0000	0.0063	0 0056	0 0063	0 0063
Four Combustion Turbines												
SO_2	39 2	51.3	50.2	394	39.2	41.2	394	66	155	145	278	280
PM/PM_{10}	43 9	68.4	68.1	148	36 0	36.0	68.0	61.0	69.0	68 1	254	236
NO_x	65.2	94.5	88.3	365	235	405	1277	398	658	632	403	678
CO	110 0	286	356	259	110.0	192	259	186	224	222	772	822
VOC (as methane)	10 96	46.2	45.8	29 1	10 96	10.98	29.1	18.6	23.1	22.6	103.2	110.2
Sulfuric Acid Mist	3 92	6 35	6.23	39.4	3 92	4 12	39.4	6 6	15 5	14 5	29 5	30 0
HAPs	2 63	3.45	3.37	9.89	2.63	2.76	9 89	4.46	6 27	6.06	14.5	14 7
Lead	0.00	0.00	0.00	0.101	0.00	0.00	0.101	0 000	0.025	0 022	0 025	0.025

[a] Based on 59 °F ambient inlet air temperature except for power augmentation at 80 °F

Table 2-6. Performance, Stack Parameters and Emissions for Existing and Proposed Natural Gas Fuel Heaters

	Natural Gas Heaters	
Performance[a]		
	1st Year of Operation	Year 2+ of Operation
Fuel Usage (scf/hr-gas)	23,218	23,218
Heat Input (mmBtu/hr-HHV)	23.71	23.71
Hours per Year	3,390	1,000
Maximum Fuel Usage (mmscf/yr)	78.71	23.22
Number of Units	4	4
Stack Parameters		
Diameter (ft)	1.5	1.5
Height (ft)	30	30
Temperature (°F)	713	713
Velocity (ft/sec)	55	55
Flow (acfm)	11,736	11,736
Emissions		
SO_2 -Basis (grains S/100 scf-gas; %S diesel)[b]	2	2
(lb/hr)	0.133	0.133
(tpy) - one unit	0.225	0.066
(tpy) - maximum[a]	0.90	0.27
NO_x - (lb/mmBtu)[c]	0.100	0.100
(lb/hr)	2.36	2.36
(tpy)	4.0	1.180
(tpy) - maximum[a]	16.0	4.7
CO - (lb/mmBtu)[c]	0.075	0.075
(lb/hr)	1.79	1.79
(tpy)	3.03	0.895
(tpy) - maximum[a]	12.1	3.6
VOC - (lb/mmBtu)[c]	0.004	0.004
(lb/hr)	0.102	0.102
(tpy)	0.173	0.051
(tpy) - maximum[a]	0.69	0.20
PM/PM10 - (lb/10^6 ft^3)[d]	6.20	6.20
(lb/hr)	0.144	0.144
(tpy)	0.244	0.072
(tpy) - maximum[a]	0.98	0.29

[a] For total number of units.

[b] Typical maximum for pipeline natural gas.

[c] Vendor information (GasTech)

[d] EPA, AP-42 Table 1.4-2 Filterable PM; higher factor used for small heater; Table 3.3-1 PM_{10}.

Table 2-7. Physical, Performance and Emissions Data for the Mechanical Draft Cooling Tower

Parameter	Martin 4 x 1 Typical
Physical Data	
Number of Cells	18
Deck Dimensions, ft	
Length	486
Width	108
Height	40
Stack Dimensions	
Height, ft	45
Stack Top Effective Inner Diameter, per cell, ft	38
Effective Diameter, all cells, ft	161.2
Performance Data	
Discharge Velocity, ft/min	1,222
Circulating Water Flow Rate (CWFR), gal/min	310,000
Design hot water temperature, °F	104
Design cold water temperature, °F	90
Heat Rejected, million Btu/hr	2,600
Design Air Flow Rate per cell, acfm	1,386,055
Liquid/ Gas (Air Flow) (L/G) Ratio	1.400
Hours of operation	8,760
Emission Data	
Drift Rate[a] (DR), percent	0.002
Total Dissolved Solids (TDS) Concentration [b] ,maximum ppm	5,000
Solution Drift [c] (SD), lb/hr	3,102
PM Drift [d,e] , lb/hr	15.51
tons/year	67.9
PM_{10} Drift	
PM_{10} Portion (percent) of PM Drift	30
PM_{10} Emissions, lb/hr	4.65
tons/year	20.4

Source: FPLE, November 19, 2001.

[a] Drift rate is the percent of circulating water

[b] TDS may range from 1000 to 9000 ppm. A TDS of 4000 results in maximum PM emissions
(See paper titled "Calculation of Realistic PM10 Emissions from Cooling Towers" presented in Appendx A.

[c] Includes water and based on circulating water flow rate and drift rate
(CWFR x DR x 8.34 lb/gal x 60 min/hr)

[d] PM calculated based on total dissolved solids and solution drift (TDS x SD)

[e] See paper titled "Calculating Realistic PM_{10} Emissions from Cooling Towers" presented in Appendix A.

Table 2-8. Summary of Maximum Potential Annual Emissions for the FPL Martin Unit 8 Combined Cycle Project

	Annual Emissions (tons/year)								
	Year 1			Year 2					
Pollutant	4 CTs Simple Cycle	4 Natural Gas Fuel Heaters	TOTAL	4 CTs/HRSGs with Duct Burners	4 Natural Gas Fuel Heaters	Cooling Tower	TOTAL	PSD Significant Emission Rate (tons/year)	PSD Review Required?
SO_2	155	0.35	156	280	0.27	NA	280	40	Yes
PM	69.0	0.38	69	254	0.29	67.9	322	25	Yes
PM_{10}	69.0	0.38	69	254	0.29	20.4	275	15	Yes
NOx	658	6.2	664	678	4.7	NA	683	40	Yes
CO	224	4.7	228	822	3.6	NA	826	100	Yes
VOC (as methane)	23.1	0.27	23	110.2	0.20	NA	110	40	Yes
Sulfuric Acid Mist	15.5	NA	15.5	30.0	Neg.	NA	30.0	7	Yes
Lead	0.025	NA	0.025	0.025	NA	NA	0.025	0.6	No

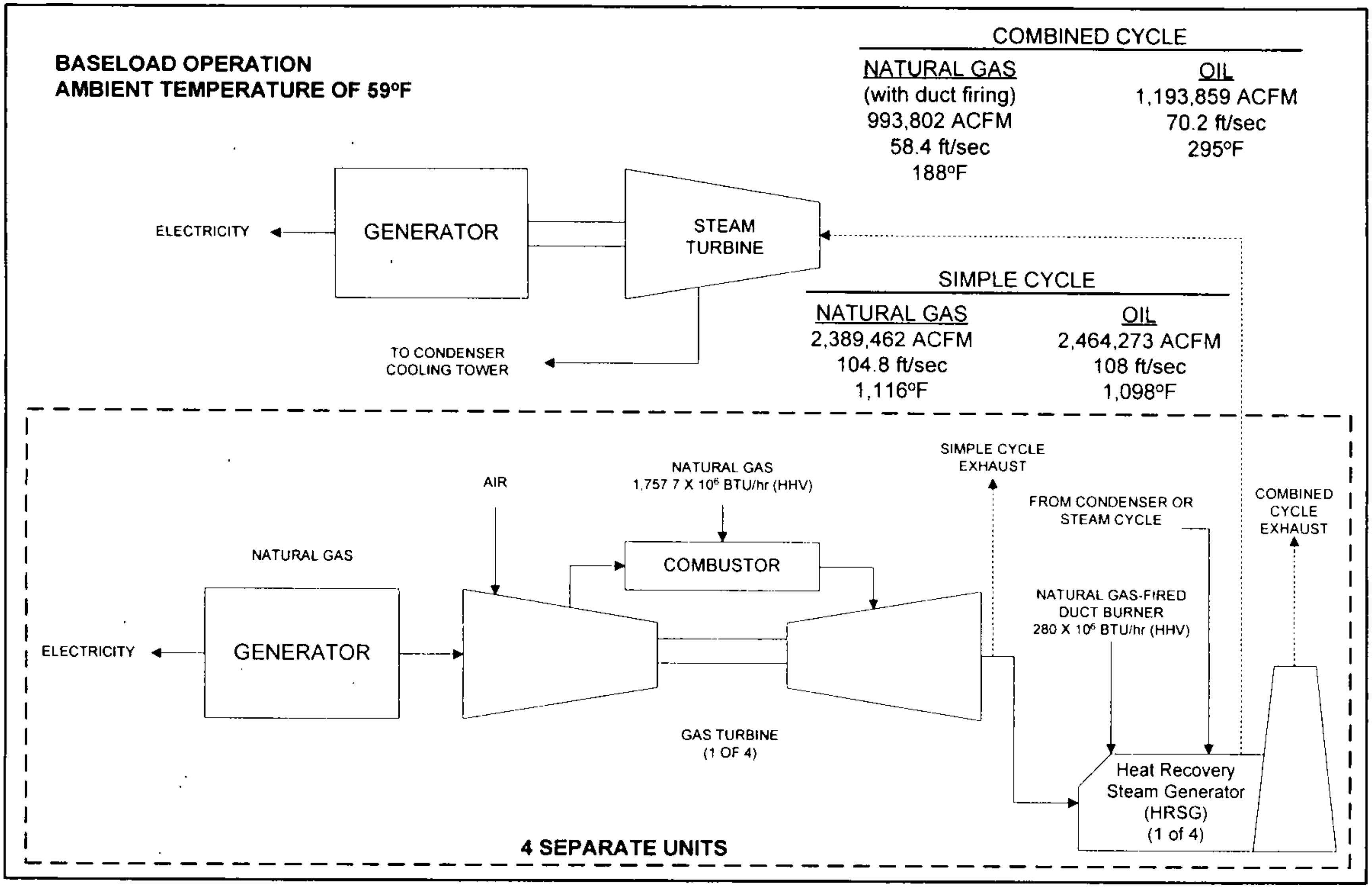

Figure 2-1. Process Flow Diagram
Baseload Operation, Ambient Temperature of 59°F

Process Flow Legend
Solid/Liquid
Gas
Steam

FPL
Martin Unit 8

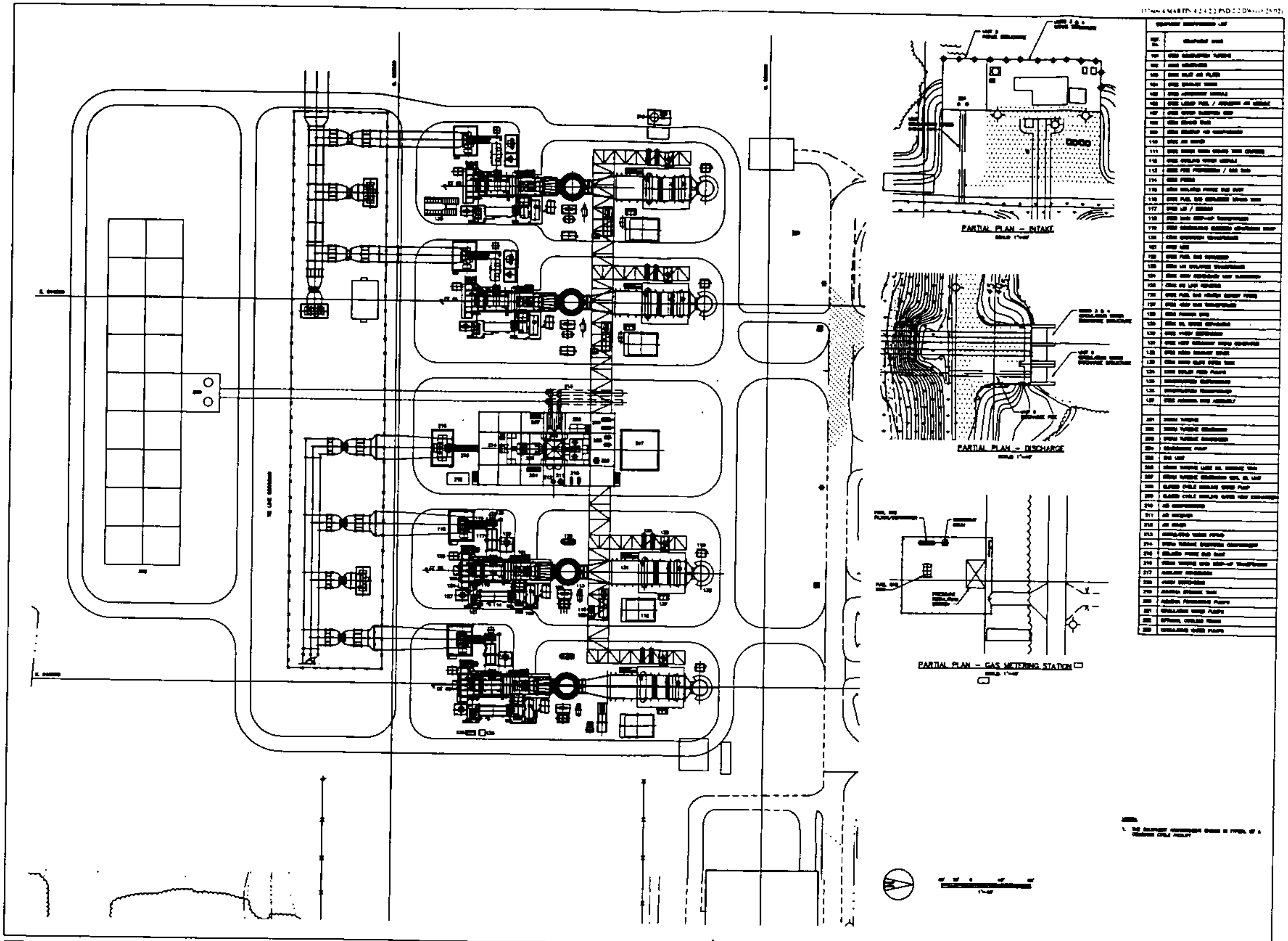

Figure 2-2. Overall Site Arrangement

Source: Black & Veatch, 2001; FPL, 2001; and Golder, 2001.

FPL
Martin Unit 8

013760/9/4 MARTIN/4 2/4.2.2 PSD/2-3.DWG (1/26/02)

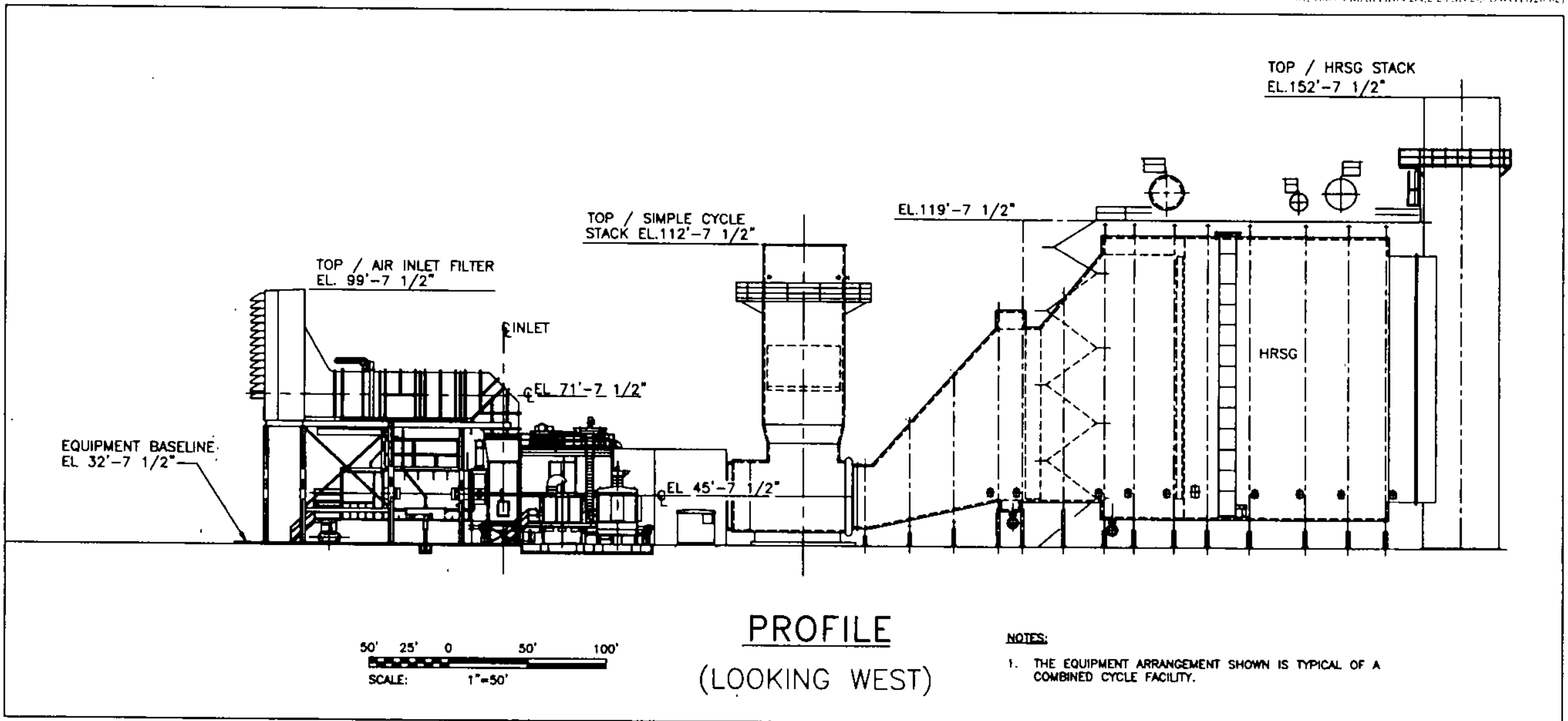

Figure 2-3. Profile of Combustion Turbine and Heat Recovery Steam Generator

Source: Block & Veatch, 2001; FPL, 2001; and Golder, 2001.

FPL
Martin Unit 8

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

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

3.1 NATIONAL AND STATE AAQS

The existing applicable national and State of 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 pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA; therefore, PSD approval authority has been granted to FDEP.

A "major facility" is defined as any 1 of 28 named source categories that have the potential to emit 100 tons per year (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.

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.

EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of SO_2, PM_{10}, and NO_2 concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1.

The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_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's PSD regulations are found in Rule 62-212.400 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 GEP stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the source (Rule 62-212.400, 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 52.21 (b)(12) and Rule 62-210.200(38), F.A.C., as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act which would be emitted by any proposed major stationary source or major modification which the Administrator, 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. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator 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 and shall provide for compliance by means which achieve equivalent results.

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

The top-down BACT approach essentially starts with the most stringent (or top) technology and emission limits 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 for using 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, for which the control technique was applied previously, must be justified. EPA has issued a draft guidance document on the top-down approach entitled *Top-Down Best Available Control Technology Guidance Document* (EPA, 1990).

3.2.3 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 above significance levels, as presented in Table 3-1.

The EPA has proposed significant impact levels for Class I areas. The levels are as follows:

Pollutant	Averaging Time	Proposed EPA PSD Class I Significant Impact Levels ($\mu g/m^3$)
SO_2	3-hour	1
	24-hour	0.2
	Annual	0.1
PM_{10}	24-hour	0.3
	Annual	0.2
NO_2	Annual	0.1

[a] $\mu g/m^3$ = micrograms per cubic meter.

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD reviews, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, EPA believes that the proposed rules concerning the significant impact levels is appropriate to assist states in implementing the PSD permit process. The FDEP has accepted the use of these significant impact levels.

Various lengths of meteorological data records 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 fewer 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.

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, will 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 (Rules 62-204.200(22); 204.360, F.A.C.). The minor source baseline for NO_2 has been set as March 28, 1988 (Rule 62-204.200(22);204.360, F.A.C). It should be noted that references to PM(TSP) are also applicable to PM_{10}.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(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. Data for a minimum of 4 months are 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 *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 a proposed major stationary facility or major modification is exempt 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 (Rule 62-212.400-3, F.A.C.). If a facility predicted impacts are less than the *de minimis* levels, therefore, preconstruction monitoring will not be required.

3.2.5 SOURCE INFORMATION/GEP STACK HEIGHT

Source information must be provided to adequately describe the proposed facility. The general type of information required for this facility is presented in Section 2.0.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant can 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 FDEP (Rule 62-210.550, 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 5 times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height 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.

3.2.6 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(o); Rule 62-212.400(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 (see Table 3-2).

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Rule 62-212.500, 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 Rule 62-2.500(2)(c)2.a., F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of NSR 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 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the 1977 CAA Amendments, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The proposed Project will be subject to one or more NSPS. The CTs will be subject to 40 CFR Part 60, Subpart GG, the duct burners will be subject to 40 CFR Part 60, Subpart Da, and the fuel oil storage tanks (2.1 million gallon capacity each) will be subject to 40 CFR Part 60, Subpart Kb.

Combustion Turbine

The CTs will be subject to emission limitations covered under Subpart GG, which limits NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired.

NO_x emissions are limited to 75 ppmvd corrected to 15-percent O_2 and heat rate, while SO_2 emissions are limited to using a fuel with a sulfur content of 0.8 percent. In addition to emission limitations, there are requirements for notifying, record keeping, reporting, performance testing, and monitoring. These are summarized below:

40 CFR 60.7 Notification and Record Keeping

(a)(1) Notification of the date of construction - 30 days after such date.

(a)(3) Notification of actual date of initial start-up - within 15 days after such date.

(a)(5) Notification of date which demonstrates CEM - not less than 30 days prior to date.

60.7 (b) Maintain records of all start-ups, shutdowns, and malfunctions.

(c) Excess emissions reports – semi-annually by the 30th day following six-month period. (required even if no excess emissions occur)

(d) Maintain file of all measurements for 2 years.

60.8 Performance Tests

(a) must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.

(d) Notification of Performance tests at least 30 days prior to them occurring.

40 CFR Subpart GG

60.334 Monitoring of Operations

(a) continuous monitoring system required for water-to-fuel ratio to meet NSPS; system must be accurate within ±5 percent.

(b) Monitor sulfur and nitrogen content of fuel.

Oil - (1): each occasion that fuel is transferred to bulk storage tank.

No intermediate storage – (2): daily monitoring required.

Duct Burner

The applicable NSPS is 40 CFR Part 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. This subpart applies to electric utility combined-cycle combustion turbines that are capable of combusting more than 250-mmBtu/hr heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam-generating unit are subject to this regulation.

The applicable NO_x and PM NSPS limits are 1.6 lb/MW (gross) and 0.03 lb/MMBtu, respectively, for the gas-fired duct burners being considered for the Project. The proposed NO_x and PM emission limits of 0.08 lb/MW and 0.008 lb/MMBtu, respectively, for the Project will be much lower than the NSPS.

Fuel Oil Storage Tank

The applicable NSPS is 40 CFR Part 60, Subpart Kb--Standards of Performance for Volatile Organic Liquid Storage Vessels (including petroleum liquid storage vessels for which construction, reconstruction, or modification commenced after July 23, 1984). The storage tanks will contain distillate fuel oil, a volatile organic liquid as defined in Subpart Kb. There are no emission limiting or control requirements under Subpart Kb for the use of distillate fuel oil. The facility, however, must perform record keeping for the type of organic liquid in the tank. These storage tanks were previously approved with the permitting of Martin Units 3 and 4.

3.4.2 FLORIDA RULES

The FDEP regulations for new stationary sources are covered in the F.A.C. The FDEP has adopted the EPA NSPS by reference in Rule 62-204.800(7): subsection (b)39 for stationary gas turbines Substation (6)(2) for the duct burners, and subsection (b)16 for volatile organic liquid storage vessels. Therefore, the facility is required to meet the same emissions, performance testings, monitoring, reporting, and record keeping as those described in Section 3.4.1. FDEP has authority for implementing NSPS requirements in Florida.

3.4.3 FLORIDA AIR PERMITTING REQUIREMENTS

The FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and 62-212.400 F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4.4 LOCAL AIR REGULATIONS

Martin County has not implemented air regulations or ordinances.

3.5 SOURCE APPLICABILITY

3.5.1 AREA CLASSIFICATION

The facility site is located in Martin County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Martin County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_2. The nearest Class I area is the Everglades National Park (NP) located about 144 km (90 miles) to the south-southwest of the facility site.

3.5.2 PSD REVIEW

Pollutant Applicability

The Martin Plant is considered to be a major facility because the emissions of several regulated pollutants are estimated to exceed 100 TPY and the emissions units are one of the 28 listed categories. The addition of the Project at the Martin Plant is a modification under the PSD rules and PSD review is required for any pollutant for which the emissions exceed the PSD significant emission rates. As shown in Table 3-3, potential emissions from the proposed Project will trigger PSD for PM(TSP), PM_{10}, SO_2, NO_x, CO, VOC and sulfuric acid mist. Impacts for these pollutants that are predicted to be above the significant impact levels require a modeling analysis incorporating the impacts from other sources is required. (Note: EPA no longer requires PSD review for hazardous air pollutants (HAPs) from PSD review. The pollutants vinyl chloride, asbestos, and beryllium are no longer evaluated in PSD review because they are addressed through the NESHAP program.)

As part of the PSD review, a PSD Class I increment analysis is required if the proposed facility's impacts are greater than the proposed EPA Class I significant impact levels. The nearest Class I area to the plant site is about 144 km from the site and a PSD Class I increment analysis and an evaluation of impacts to AQRVs is required.

Emission Standards

The applicable NSPS for the CTs is 40 CFR Part 60, Subpart GG. The proposed emissions for the turbines will be well below the specified limits (see Section 4.0).

The applicable NSPS for the duct burners is 40 CFR Part 60, Subpart Da. The proposed emissions for the duct burners will be well below the specified limits (see Section 4.0).

The fuel oil storage tanks will have a maximum storage capacity of 2.1 million gallons of No. 2 fuel oil each. Since the storage tank has a capacity greater than 40 cubic meters (m^3)(approximately 10,568 gallons), the applicable NSPS is 40 CFR Part 60, Subpart Kb. Each storage tank will contain distillate fuel oil, a volatile organic liquid as defined in Subpart Kb, with a true vapor pressure of 0.022 pound per square inch (psi) at 100°F. Because the fuel oil is expected to have a maximum true vapor pressure of less than 3.5 kilopascals (kPa) or 0.51 psi, only the minor monitoring of operating requirements specified in 40 CFR 60 116b(a) and (b) will apply.

Ambient Monitoring

Based on the estimated pollutant emissions from the proposed plant (see Table 3-4), a pre-construction ambient monitoring analysis is required for PM_{10}, SO_2 , NO_2, CO, and O_3 (based on VOC emissions). If the net increase in impact of other pollutants is less than the applicable *de minimis* monitoring concentration (100 TPY in the case of VOC), then an exemption from the pre-construction ambient monitoring requirement is available by Rule 62-212.400(3)(e) F.A.C. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

As shown in Table 3-4, the proposed plant's impacts are predicted to be below the applicable *de minimis* monitoring concentration levels for all pollutants. Therefore, pre-construction monitoring is not required to be submitted for this facility. The emissions of VOC are above the *de minimis* monitoring threshold. The monitoring analysis is presented in Section 5.0.

GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m [213 feet (ft)] high. The stacks for the Project will be 120 ft for the HRSG stacks and 80 ft for the simple cycle stacks. These stack heights do not exceed the GEP stack height. However, as discussed in Section 6.0, Air Quality Modeling Approach, since the stack height is less than GEP, building downwash effects must be considered in the modeling analysis. As a result, the potential for downwash of the CT emissions caused by nearby structures are included in the modeling analysis.

3.5.3 NONATTAINMENT REVIEW

The facility site is located in Martin County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment requirements are not applicable.

3.5.4 OTHER CLEAN AIR ACT REQUIREMENTS

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

EPA's Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units which fall under the program are referred to as affected units. The EPA regulations would be applicable to the proposed facility for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the date on which the unit commences operation (e.g., first fire).

The permit would require the units to hold SO_2 emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT or lowest achievable emission rate (LAER) for new units. An allowance is a market-based financial instrument that is equivalent to 1 ton of SO_2 emissions. Allowances can be sold, purchased, or traded.

Continuous emission monitoring (CEM) for SO_2 and NO_x is required for gas fired and oil fired affected units. When an SO_2 CEM is selected to monitor SO_2 mass emissions, a flow monitor is also required. Alternately, SO_2 emissions may be determined using procedures established in Appendix D, 40 CFR Part 75 (flow proportional oil sampling or manual daily oil sampling). CO_2 emissions must also be determined either through a CEM (e.g., as a diluent for NO_x monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I). The acid rain CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart GG.

New units are required to meet the requirements by the later of January 1, 1995, or not later than 90 days after the unit commences commercial operation.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels

Pollutant	Averaging Time	AAQS ($\mu g/m^3$) Primary Standard	AAQS Secondary Standard	AAQS Florida	PSD Increments ($\mu g/m^3$) Class I	PSD Increments Class II	Significant Impact Levels ($\mu g/m^3$) [b]
Particulate Matter[c] (PM_{10})	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	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[c]	8-Hour Maximum[d]	157	157	157	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM_{10}) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

[a] Short-term maximum concentrations are not to be exceeded more than once per year.

[b] Maximum concentrations are not to be exceeded.

[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 g/m³ (3-year average of 98th percentile) and an annual standard of 15 g/m³ (3-year average at community monitors). These standards are not yet applicable and have been challenged at the federal level.

[d] 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm or less. The standard is not yet applicable and has been challenged at the federal level.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-204, F.A.C.

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

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Nitrogen Dioxide	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
Mercury	NESHAP	0.1	0.25, 24-hour

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 established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
g/m^3 = micrograms per cubic meter.

[a] Short-term concentrations are not to 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.

Sources: 40 CFR 52.21.
Rule 62-212.400

Table 3-3. Maximum Emissions Due to the Proposed Project Compared to the PSD Significant Emission Rates

Pollutant	Pollutant Emissions (TPY) Potential Emissions from Proposed Project[a]	Pollutant Emissions (TPY) Significant Emission Rate	PSD Review
Sulfur Dioxide	280	40	Yes
Particulate Matter [PM(TSP)]	322	25	Yes
Particulate Matter (PM_{10})	275	15	Yes
Nitrogen Dioxide	683	40	Yes
Carbon Monoxide	826	100	Yes
Volatile Organic Compounds	110	40	Yes
Lead	0.025	0.6	No
Sulfuric Acid Mist	30.0	7	Yes
Total Fluorides	NEG	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Mercury	2.3×10^{-3}	0.1	No

Note: NEG = Negligible.

[a] Based on emissions from operating at base load at 59°F:

1. Combined Cycle
   - 100-percent load, natural gas – 4,480 hours
   - 100-percent load with duct burners, natural gas – 2,880 hours
   - 100-percent load with duct burners and high power mode – 400 hours
2. Simple Cycle
   - 100-percent load, natural gas – 500 hours
   - 100-percent load, oil firing – 500 hours

Includes four natural gas heaters (see Table 2-6) and cooling tower (see Table 2-7).

Table 3-4. Predicted Net Increase in Impacts Due to the Proposed Project Compared to PSD *De Minimis* Monitoring Concentrations

Pollutant	Concentration ($\mu g/m^3$)		
	Predicted Increase in Impacts[a]		*De Minimis* Monitoring Concentration
	4 on 1 CC	4 SC	
Sulfur Dioxide	8.64	0.84	13, 24-hour
Particulate Matter (PM_{10})	4.01	0.23	10, 24-hour
Nitrogen Dioxide	0.56	0.23	14, annual
Carbon Monoxide	16.2	1.42	575, 8-hour
Volatile Organic Compounds	110 TPY	22.6 TPY	100 TPY

Note: SC = simple cycle operation

CC = combined cycle operation

[a] See Section 6.0 for air dispersion modeling results.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_x, SO_2, CO, PM/PM_{10}, and sulfuric acid mist (see Section 3.0). The maximum potential annual emissions of these pollutants from the proposed "F" Class CTs are summarized in Table 2-5.

This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a top-down approach. 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)]. The analysis must, by definition, be specific to the Project (i.e., case by case).

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for CTs are codified in 40 CFR 60, Subpart GG and summarized in Appendix B. The applicable NSPS emission limit for NO_x is 75 parts per million by volume dry (ppmvd) corrected for heat rate and 15-percent O_2. For the CTs being considered for the Project, the NSPS emission limit for NO_x, with the NSPS heat rate correction, is over 100 parts per million (ppm) firing natural gas and distillate oil (corrected to 15-percent O_2 at a fuel-bound nitrogen content of 0.015 percent). The proposed NO_x emission limits for the Project in combined cycle mode will be 40 times lower than the NSPS when firing natural gas and 8 times lower than the NSPS when firing distillate oil.

The applicable NSPS for the duct burner are codified in 40 CFR 60, Subpart Da and is also summarized in Attachment B. The applicable NO_x emission limit is 1.6 lb/MW-hr. The combined CT and duct burner emissions rate with SCR of 2.5 ppmvd corrected to 15-percent O_2 is equivalent to about 0.08 lb/MW-hr or over 10 times lower than the applicable NSPS.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 OVERVIEW OF PROPOSED BACT

In recent permitting actions, BACT for heavy-duty industrial gas turbines has been determined. These decisions established emission rates that were achieved through the use of advanced DLN combustors and SCR for limiting emissions of NO_x, good combustion practices for minimizing CO and VOC emissions, and the use of clean fuels (natural gas) for control of other emissions, including PM_{10} and SO_2. The BACT proposed for the Project is consistent with these permits. The results of the BACT analysis have concluded the following controls as BACT for the Project operating in combined cycle mode.

1. The Project when in combined cycle operation will use state-of-the-art DLN combustion technology and SCR to achieve gas turbine exhaust NO_x levels of no greater than 2.5 ppmvd corrected to 15-percent O_2 when firing natural gas and 12 ppmvd corrected to 15-percent O_2 when firing. For the first year and limited operation in the future, the Project will operate in simple cycle mode. The simple cycle BACT emission rates for NO_x are 9 ppmvd corrected to 15-percent O_2 when firing gas and 42 ppmvd corrected to 15-percent O_2 when firing oil.
2. CO emissions when firing natural gas will be limited to 9 ppmvd at baseload to 50 percent load (simple and combined cycle) 24.5 ppmvd with duct firing (combined cycle) and 29.6 ppmvd with HPM and duct firing. When firing distillate oil CO will be limited to 20 ppmvd (simple and combined cycle).
3. Emission rates of PM_{10} and SO_2 will be limited using natural gas.

A summary of the emission rates proposed as BACT is presented in Table 4-1. Excess emissions proposed for the Project is addressed in Section 2.5.

4.3.2 NITROGEN OXIDES – COMBINED CYCLE

Technology Description

The BACT analysis was performed based on those available and feasible control technologies that can provide the maximum degree of emission reduction for NO_x emissions. An evaluation of the available and feasible control technologies determined that combustion along with SCR could provide the maximum degree of emission reduction. SCONO$_x$™ is commercially available but has not been demonstrated on "F" Class combustion turbines. Other available technologies such as NO$_x$Out, Thermal DeNO$_x$, NSCR, and XONON™ Combustion System were evaluated and determined to be technically infeasible or not commercially demonstrated for the Project. Appendix B presents a discussion of these NO_x control technologies and their feasibility for the Project.

DLN combustor technology has been offered and installed by manufacturers to reduce NO_x emissions by inhibiting thermal NO_x formation through premixing fuel and air prior to combustion and providing staged combustion to reduce flame temperatures. NO_x emissions from 25 ppmvd (corrected to 15-percent O_2) and less has been offered by manufacturers for advanced CTs. This technology prevents pollution since NO_x emissions are inhibited from forming. When firing distillate oil, NO_x is limited using water injection to 42 ppmvd (corrected to 15-percent O_2).

SCR is a post-combustion process where NO_x in the gas stream is reacted with ammonia in the presence of a catalyst to form nitrogen and water. It is available from vendors for combined cycle applications. The reaction occurs typically between 600°F and 750°F, which occur in combined cycle units in the HRSG. SCR has been installed and operated on combined cycle facilities using catalysts with temperature ranges from 600 to 750°F and generally achieving 9 ppmvd (corrected to 15-percent O_2) or less while burning natural gas.

Ammonium salts (ammonium sulfate and ammonium bisulfate) are formed by the reaction of sulfur oxides in the gas stream and ammonia. These salts are highly acidic and special precautions in materials and ammonia injection rates must be implemented to minimize their formation.

Ammonia injected in the SCR system, which does not react with NO_x, is emitted directly and referred to as ammonia slip. In general, SCR manufacturers guarantee an ammonia slip to be no more than 9 ppmvd corrected to 15-percent oxygen (O_2). SCR is technically feasible for the Project.

Although $SCONO_x$™ is available, it has not been demonstrated on a "F" Class combustion turbine. Performance data on future applications on "F" Class turbines considering $SCONO_x$™ will only likely be available after 2002, well after the facility is scheduled for construction. The $SCONO_x$™ system has only been operated on a 32-MW facility in California since 1996 and a 5 MW unit in Massachusetts since 1999. The scale up of this complicated technology should not be underestimated. The $SCONO_x$™ technology installed on an "F" Class turbine would involve about a dozen or more different chambers of catalyst for absorption and regeneration. Every 15 to

30 minutes, dampers would be operated to isolate a particular catalyst chamber for regeneration. Each regeneration cycle must isolate the chamber so that O_2 is not introduced and regeneration gas (hydrogen) is introduced. Seal leaks could be significant as applied to the large volume flows associated with a "F" Class turbine. Although the amount of sulfur in natural gas is very low, the SCONO$_x$™ catalyst is poisoned with sulfur compounds requiring the installation of the SCOSO$_x$™ to further remove sulfur compounds as part of the overall system. While the distillate oil proposed for the Project will contain 0.05 percent sulfur or less, the amount will be about 20 times higher than that normally contained in natural gas. The ability of SCOSO$_x$™ to further remove sulfur compounds as part of the overall SCONO$_x$™ system has not been demonstrated when firing distillate oil.

Over the last several years, the permitting trend for advanced CTs, even in combined cycle configuration, is the use of DLN combustors with SCR. In Region IV, the predominate emission rate established as BACT has been 3.5 ppmvd corrected to 15-percent O_2 when firing natural gas. Several projects in Florida have established case-by-case BACT of 3.5 and 2.5 ppmvd corrected to 15-percent O_2 when firing natural gas using DLN and SCR.

The proposed CTs will be fired with natural gas and distillate oil. The BACT evaluation was based on DLN combustors in combination with SCR and SCONO$_x$™. The BACT evaluation considered both 3.5 and 2.5 ppmvd corrected to 15 percent oxygen when firing natural gas.

The following sections present a summary of the economic, environmental, and energy impacts of the available, technically feasible and demonstrated control technology alternatives for the combined cycle units. Appendix B contains the detailed information on the costs, environmental, and energy impacts.

Impacts Analysis – 3.5 ppmvd Corrected to 15 Percent O_2

Economic--The total estimated capital costs of SCR on a CT/HRSG are $2,365,937. The total annualized cost of applying SCR with DLN combustion is $1,136,656. Appendix B contains the detailed cost estimates for the capital and annualized costs. The incremental cost effectiveness of adding SCR to the DLN combustors is estimated at $4,216 per ton of NO_x removed.

The capital and annualized costs for SCONO$_x$™ are based on a budgetary cost estimate provided by ABB Alstom Environmental Systems. The budgetary estimate of capital costs for SCONO$_x$™ on one turbine/HRSG unit for one combined cycle unit is \$26.6 million. In contrast, the capital costs for SCR is about \$2.4 million, which clearly is about 10 times less costly than $SCONO_x$™ of SCR. The annualized cost of $SCONO_x$™ is estimated at \$5.3 million. The cost effectiveness of $SCONO_x$™ is \$19,800 per ton of NO_x. In contrast, the cost effectiveness of SCR is about \$4,200 per ton of NO_x removed. The cost effectiveness of $SCONO_x$™ is over 400 percent higher than SCR with uncertainty in its demonstrated feasibility. It should be noted that the annualized costs for $SCONO_x$™ did not include provisions for required mechanical maintenance activities.

Environmental--The maximum predicted NO_x impact of the Project is considerably below the NO_2 PSD Class II increment of 25 $\mu g/m^3$ (annual average) and the AAQS of 100 $\mu g/m^3$ (annual average). The maximum annual impact for the Project is about 0.6 $\mu g/m^3$ when firing natural gas, which is less than 1 percent of the AAQS. The addition of SCR will reduce NO_x emissions by about 270 TPY per CT/HRSG (about 67-percent reduction) from the combined cycle operation beyond those achieved through the use of DLN combustors.

The use of DLN combustor technology is "pollution prevention". The use of SCR has associated primary and secondary environmental impacts. Emissions of ammonia and ammonium salts (such as ammonium sulfate and bisulfate) will occur. Ammonia emissions with the use of SCR are a result of unreacted ammonia that may be emitted. Vendors typically provide ammonia slip guarantees of 9 ppmvd corrected to 15-percent O_2. Maximum ammonia emissions are 112 TPY at the guarantee ammonia slip level. However, this level of ammonia slip occurs only as the catalyst ages. Initial ammonia slip levels are less than 5 ppmvd. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10} and up to 11.9 TPY could be emitted.

The electrical energy required to run the SCR system and the backpressure from the turbine will reduce the available power from the Project. The backpressure is a result of the catalyst modules located in the exhaust gas stream in the HRSG. With use of DLN combustors at an emission level of 9 ppmvd (corrected to 15-percent O_2), the backpressure to reduce NO_x to 3.5 ppmvd (corrected to 15-percent O_2) is about 2.5 inches of water gauge. This backpressure reduces the power generated by the combustion turbine. This lost power, which would otherwise be available to the electrical system, will have to be replaced by other less efficient units. The replacement power will cause air pollutant emissions that would not have occurred without SCR. The net reduction in emissions with SCR (i.e., reduction in NO_x minus ammonia and secondary emissions), when all criteria pollutants are considered, will be about 140 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted.

SCR will require the construction and maintenance of storage vessels for aqueous ammonia for use in the reaction. Ammonia has potential health effects, and the construction of ammonia storage facilities triggers the application of at least three major standards: Clean Air Act (section 112), Occupational Safety and Health Administration (OSHA) 29 CFR 1910.1000, and OSHA 29 CFR 1910.119. The Project proposes using aqueous ammonia for the SCR system.

While ammonia is not used or emitted from a $SCONO_x$™ system, there are substantial natural gas, steam, and back pressure for the $SCONO_x$™ system that would directly result in environmental impacts. $SCONO_x$™ requires about 17,795 lb/hr of steam and 80 lb/hr of natural gas. In addition, the backpressure of the $SCONO_x$™ system is 200 percent over that of the SCR. This increased energy use would create additional criteria pollutants of about 41 TPY per unit and about 23,000 TPY per unit of additional carbon dioxide emissions compared to the Project using SCR (i.e., about 3,400 TPY per unit).

Energy--Energy penalties occur with SCR. With SCR, the output of the CT can be reduced over that of advanced low-NO_x combustors due to the backpressure on the CT. In combined cycle configuration and with a low base emission level (i.e., 9 ppmvd corrected to 15-percent O_2) and 67 percent NO_x reduction, the output reduction is estimated to be about 0.3 percent. This penalty is the result of the SCR pressure drop, which would be about 2.5 inches of water and would amount to about 4,532,000 kWh per year in potential lost generation. The energy required by the SCR equipment would be about 700,800 kWh per year. Taken together, the total lost generation and energy requirements of SCR of 5,233,000 kWh per year could supply the electrical needs of about 426 residential customers. To replace this lost energy, an additional 5.4×10^{10} British thermal units per year (Btu/yr) or about 54 million cubic feet per year (ft^3/yr) of natural gas would be required.

$SCONO_x$™, in contrast to SCR, is very energy intensive. The $SCONO_x$™ system has about 2 times more backpressure on the turbine requires steam and natural gas for the regeneration process. The natural gas needed to generate the steam for the $SCONO_x$™ system is equivalent to 26.3 MMBtu/hr/unit or 230,000 MMBtu per year per unit. The overall energy usage is equivalent to about 34,800,000 kW per hours per year or equivalent energy for about 2,900 residential customers.

The energy equivalence in terms of natural gas usage is 362 million cubic feet per year or about 7 times that of SCR. When all the energy requirements for $SCONO_x$™ are considered, it is about 2.32 percent of the combustion turbine heat input. In contrast, SCR results in an additional 0.35 percent of the combustion turbine heat input.

Technology Comparison--The proposed Project will use an advanced heavy-duty industrial gas turbine with advanced DLN combustors. This type of machine advances the state-of-the-art for CTs by being more efficient and less polluting than previous CTs. Integral to the machine's design is DLN combustors that prevent the formation of air pollutants within the combustion process, thereby minimizing the amount of add-on controls that can have an impact on the environment. An analogy of this technology is a more efficient automotive engine that gives better mileage and reduces pollutant formation without the need of a catalytic converter.

An advanced gas turbine is unique from an engineering perspective in two ways. First, the advanced machine is larger and has higher initial firing (i.e., combustion) temperatures than conventional turbines. This results in a larger, more thermally efficient machine. For example, the electrical generating capability of the proposed "F" class advanced machine is about 170 MW compared to the 70 to 120 MW conventional machines. The higher initial firing temperature (i.e., 2,600°F) results in about 20 percent more electrical energy produced for the same amount of fossil fuel used in conventional machines. This has the added advantage of producing less air pollutant emissions (e.g., NO_x, PM, and CO) for each MW generated. While the increased firing temperature increases the thermal NO_x generated, this NO_x increase is controlled through combustor design.

The second unique attribute of the advanced machine is the use of DLN combustors that will reduce NO_x emissions to 9 ppmvd when firing natural gas. Thermal NO_x formation is inhibited by using staged combustion techniques where the natural gas and combustion air is premixed prior to ignition. This level of control will result in NO_x emissions of about 0.04 lb/10^6 Btu for gas firing, which are less than half of the emissions generated from conventional fossil fuel-fired steam generators.

The use of SCR on combined cycle projects has been a recent trend in Florida and Region IV. Its use can limit NO_x emissions, while retaining much of the benefits of the advanced CT technology in combined cycle configuration.

From a technology standpoint, SCR has been demonstrated as feasible on over 100 combined cycle projects. In contrast, $SCONO_x$™ has only been operating over a few years on small turbines that are over ten times smaller than the "F" Class turbine being proposed for the Project. As noted from the information in Appendix B, the $SCONO_x$™ system requires a considerable amount of mechanical equipment that must be operated in a high volume flow field. SCR has no moving parts to complicate operation. Over time, there is considerable uncertainty in the maintenance and replacement requirements of the mechanical components of the $SCONO_x$™ system on a large turbine.

Economic Impact Analysis – 2.5 ppmvd Corrected to 15 Percent O_2-- Appendix B contains cost evaluation for a NO_x emission rate of 2.5 ppmvd corrected to 15-percent O_2 when firing natural gas. The NO_x emission rate when firing distillate oil was kept at 12 ppmvd corrected to 15-percent O_2. The cost for SCR were adjusted based on vendor estimates. For $SCONO_x$™, the capital cost was kept the same and only the catalyst changeout cost were increased.

The results of the evaluation for total cost effectiveness are presented below:

	SCR @ 3.5 ppmvd	$SCONO_x$™ @ 3.5 ppmvd
Total Annualized Costs	$1,136,656	$5,328,516
Cost Effectiveness	$4,216	$19,765
	SCR @ 2.5 ppmvd	$SCONO_x$™ @ 2.5 ppmvd
Total Annualized Costs	$1,479,017	$5,682,303
Cost Effectiveness	$4,918	$18,894

Note: Total tons removed at 3.5 ppmvd is 270 TPY and at 2.5 ppmvd is 301 TPY.

Assuming that $SCONO_x$™ can achieve 2.0 ppmvd corrected to 15-percent O_2 when firing gas the cost effectiveness is about $18,000 per ton of NO_x removed (for about 316 TPY removed). It should be emphasized that $SCONO_x$™ is not considered a demonstrated technology for "F" Class combustion turbines and has not been used or proposed when firing distillate oil. Moreover, the operational experience is non existent on "F" Class turbines. Indeed, the cost effectiveness did not consider any additional operational cost of this technology as a result of the extensive mechanical equipment required. Moreover, $SCONO_x$™ has considerable collateral environmental and energy impacts as noted in the application.

The incremental cost using SCR from an emissions rate of 3.5 ppmvd corrected to 15-percent O_2 to 2.5 ppmvd corrected to 15-percent O_2 is shown below:

Incremental Cost Effectiveness (3.5 to 2.5 ppmvd)
\$1,479,017 Annualized cost for SCR at 2.5 ppmvd
\$1,136,656 Annualized cost for SCR at 3.5 ppmvd
\$342,360.55 Difference
100.69 TPY emissions at 2.5 ppmvd
131.84 TPY emissions at 3.5 ppmvd
31.15 TPY reduced
\$10,989.03 Incremental Cost Effectiveness

Technical Feasibility--There are also significant issues in demonstration compliance with an emission limit as low as 2.5 ppmvd corrected to 15-percent O_2. Such problems will occur with an emission rate of 3.5 ppmvd but be exacerbated with even a lower limit. The difficulties include the reliability of the continuous emission monitoring measurement, availability and stability of calibration gases, precision and accuracy of reference measurements (e.g., EPA Method 7E) and increased ammonia slip. Moreover, there is a general lack of experience in demonstrating compliance over the long term. These concerns are being evaluated by the Electric Power Research Institute (EPRI) Low Level NO_x Project, and the project has validated many of these concerns. While this project is still on going, the information to date suggests the potential trend of increasing ammonia injection rates to maintain low NO_x levels and difficulties in monitor performance. The latter included increased span drift and bias test failures during RATA testing. As a result of these monitoring issues, a longer averaging time is considered appropriate for a 2.5 ppmvd emission limit.

Environmental--There would also be collateral environmental consequences to achieve a NO_x emission rate of 2.5 ppmvd corrected to 15-percent O_2 rather than 3.5 ppmvd corrected to 15-percent O_2. This will be a direct result of increased backpressure on the turbine resulting from more catalyst volume required. Backpressure will increase by 15 percent over the proposed BACT emission rate resulting in increased energy losses and greater secondary emissions. Indeed, the lost energy will increase by 679,759 kW-hours/year/turbine or enough additional electric power to support about 57 residential customers for a year. To supply this lost energy, at least 0.8 TPY of additional criteria pollutants as well as 443 TPY of additional carbon dioxide would be generated.

Proposed BACT and Rationale for Combined Cycle Operation

The proposed BACT for combined cycle operation is advanced DLN combustion technology and SCR. The proposed NO_x emissions level using this technology is 2.5 ppmvd corrected to 15-percent O_2 when firing natural gas and 12 ppmvd corrected to 15-percent O_2 when firing distillate fuel oil. This combination of the technology can achieve the maximum amount of emission reduction available, technically feasible and demonstrated for the Project. SCR cannot be rejected based on the economic, environmental, and energy impacts given the recent BACT decisions on other similar projects.

$SCONO_x$™ is rejected as BACT based on significant energy, environmental and economic impacts. The costs are significantly different between SCR and $SCONO_x$™, yet both technologies can achieve the same level of NO_x reduction. From an environmental perspective, the only advantage of $SCONO_x$™ is the lack of ammonia slip. Ammonia is an unregulated air pollutant and ammonia slip can be minimized through design and operation of the SCR system. $SCONO_x$™ requires steam and natural gas that SCR does not require. These have direct environmental consequences in the form of additional air pollutant emissions including about 23,000 TPY per unit of additional CO_2. Thus, the energy and other environmental disadvantages of $SCONO_x$™ outweigh any advantages in the reduction of these emissions. Taking together the energy, economic and environmental impacts and other costs, $SCONO_x$™ is rejected as BACT. In addition, the use of distillate fuel oil further limits the ability of $SCONO_x$™ to be used for the Project.

4.3.3 NITROGEN OXIDES – SIMPLE CYCLE

Technology Description

The Martin Unit 8A and 8B are proposed to operate in simple cycle mode during the first year of operation (3,390 hours/year) and limited hours when combined cycle operations begins (1,000 hours/year). The emissions rates established as BACT in attainment areas have predominately been based on emissions using DLN combustion technology when firing natural gas and water injection when firing oil. For the GE Frame 7FA turbine these emission rates established as BACT have been 9 ppmvd corrected to 15-percent O_2 when firing natural gas and 42 ppmvd corrected to 15-

percent O_2 when firing distillate oil. These are the current GE guarantees. FDEP has approved numerous projects with these emission limits as BACT including the BACT determination Martin Units 8A and 8B issued in 2000.

In its Guidance for Power Plant Siting and Best Available Control Technology document, the California Air Resources Board (CARB 1999) states that the most stringent BACT limit for NO_x from a simple cycle combustion turbine is 5 ppmv (3-hour average) based on the Carson Energy Group facility in California. This project is a small (<50 MW) aeroderivative turbine. In a discussion of exhaust gas temperature considerations, CARB also states that whereas catalytic control systems are feasible for aeroderived simple cycle gas turbines, "the high exhaust temperatures approaching 1,100°F" of industrial frame gas turbines (such as the GE industrial frame series) "may require case-by-case evaluation regarding the feasibility of NO_x control through selective catalytic reduction."

Manufacturers of SCR were contacted regarding application of "hot" SCR on large frame combustion turbines. This includes the "E" class and "F" Class turbines. The "E" Class turbines have slightly lower exhaust temperatures (up to 1,100°F) than the "F" Class turbines (up to 1,200°F). However, the exhaust temperatures for both type of turbines exceed 1,000°F and some type of cooling is required. Applications of SCR to simple cycle projects have been applied to one known "E" Class turbine and four known "F" Class turbines (two operating and two planned for operation). Engelhard Corporation remains the only supplier providing application of "hot" SCR above 1,000°F. Engelhard's experience with "hot" SCR lists 112 turbines that are either operating or planned to operate. Of these 112 turbines, only 5 turbines are "E" or "F" Class in size. Through discussion with Kenneth Burns of Engelhard Corporation, as the only manufacturer of the high-temperature zeolite catalyst for hot SCR systems, there are currently no projects involving a dual-fuel "F" Class combustion turbine and hot SCR. In all "hot" SCR applications on and "F" Class turbines, the turbines have only been firing with natural gas and the exhaust gases are cooled to 1,025°F or less.

The application of "hot" SCR is not considered technically feasible for the Project. This is based on the lack of demonstration of this technology on dual fuel gas turbines and anticipated technical difficulties associated with oil firing. In the 1990s, there are four simple cycle combustion turbine projects that have installed SCR with any significant operating experience.

These projects are:

- Redding Municipal Power – 3 GE Frame 5 CTs fired with natural gas. The CTs are operated as a peaking facility.
- SoCal Gas Company – 4 Solar Centaur CTs (4MW equivalent each) fired with natural gas. The CTs are operated in intermediate cycling duty.
- UnoCal Brea Research Center – a single 4 MW CT firing natural gas. The CT operates in intermediate to base load duty.
- Puerto Rico Electric Power Authority (Cambalache Facility) – 3 ABB Type 11 N (83 MW each) firing No. 2 distillate oil.

The SCRs for all these CTs were designed to operate at temperatures less than 1,000°F. Many of the smaller CTs have exhaust temperatures less than 1,000°F. The Cambalache Facility had a once through steam generator in the ductwork leading to SCR used for power augmentation that reduced the catalyst temperature to less than 1,000°F. Experience on these systems has shown significant catalyst deactivation occurs with peaking and intermediate cycling duty while firing natural gas. Under these conditions catalyst deactivation has occurred after operating from 350 to 4,000 hours. For intermediate-base load duty and firing natural gas, catalyst deactivation improved but still occurred after 8,000 hours of operation and well less than the catalyst guarantee. When firing distillate oil, catalyst deactivation occurred after 600 hours. The SCR system for the Cambalache Facility had significant problems resulting in the removal of the SCR catalyst. The units proposed for Martin Unit 8 will be peaking units that will be limited to 1,500 hours per year. The normal operation of these units will be fast startups with maximum operation of 16 hours/day or less. Startup is relatively a short time period (i.e., about 30 minutes) with temperatures exceeding 1,000°F. This type of operation will result in wide variations of exhaust temperatures causing significant thermal stresses on downstream equipment. The need to use oil is also a limiting factor in the application of SCR for the Project because of the demonstrated technical difficulties experienced with oil firing in "hot SCR" systems. Inherent in the consideration of technical feasibility, is the ability of the alternative control technology to meet an emission limit.

"Hot" SCR has even been determined not to be feasible in ozone non-attainment areas where LAER is the applicable criteria rather than BACT. For example, in the summer of 2000, the Maryland Department of Environment (MDE) evaluated the installation of "hot" SCR on GE Frame 7FA turbines for the Old Dominion Electric Cooperative Rock Springs Project. The MDE concluded that

- Redding Municipal Power – 3 GE Frame 5 CTs fired with natural gas. The CTs are operated as a peaking facility.
- SoCal Gas Company – 4 Solar Centaur CTs (4MW equivalent each) fired with natural gas. The CTs are operated in intermediate cycling duty.
- UnoCal Brea Research Center – a single 4 MW CT firing natural gas. The CT operates in intermediate to base load duty.
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In addition, the installation of "hot" SCR has considerable co-lateral economic, environmental and energy disadvantages that are components of the BACT analysis. Many of these disadvantages have been identified for modern combustion turbines in guidance issued by John Seitz, Director of EPA's Office of Air Quality Planning and Standards (EPA, 2000a).

Impact Analyses

Economic Impacts

The total capital and annualized cost for SCR applied to simple cycle operation for one GE Frame 7FA was developed (Golder, 2000). The costs were developed using EPA Cost Control Manual (EPA, 1990 & 1993). Vendor based estimates were used for the SCR system, while assuming the technology could consistently achieve 3.5 ppmvd corrected to 15-percent O_2 when firing natural gas and 15 ppmvd corrected to 15-percent O_2 when firing distillate oil. It should be noted that these emission limits have not been demonstrated in practice. In performing the economic analysis, standard EPA recommended cost factors were used. A capital recovery period of 15 years at 7 percent was used for determining the annualized costs of capital. The total capital costs of "hot" SCR for the simple cycle operation are estimated to be $5,866,600. This is a factor of two higher than SCR installed in the HRSG. The total annualized cost of applying SCR with DLN combustion and water injection is $1,728,750 for 3,390 hours of operation and $1,659,000 for 1,000 hours of operation. The incremental cost effectiveness of adding SCR to the DLN combustors and water injection (for oil firing) is estimated at about $25,200 and $57,700 per ton of NO_x removed for 3,390 hours and 1,000 hours, respectively. This cost effectiveness for "hot" SCR is substantially higher than applying SCR in the HRSG and higher than that previously considered appropriate for BACT for NO_x.

Energy Impacts

Significant energy penalties occur with "hot" SCR. With SCR, the output of the CT can be reduced by up to 0.50 percent over that of advanced low-NO_x combustors. This is the estimated reduction in CT output resulting from "hot" SCR. This penalty is the result of the SCR pressure drop, which would be about 4 inches of water and would amount to about 3,870,000 kWh per year in potential lost generation for 3,390 hours per year. This lost energy could supply the electrical needs of about 320 residential customers. To replace this lost energy, an additional 37.5 x 10^{10} British thermal units per year (Btu/yr) or about 37 million ft^3/yr of natural gas would be required.

Environmental Impacts

The maximum predicted NO_x impacts using the DLN technology with the simple cycle unit is considerably below the NO_2 PSD Class II increment of 25 $\mu g/m^3$ (annual average) and the AAQS of 100 $\mu g/m^3$ (annual average). The maximum annual impact for the Project in simple cycle operation is less than 1 $\mu g/m^3$ (PSD significant impact level), which is less than one percent of the AAQS and less than the significant impact level of 1 $\mu g/m^3$. The effect of adding "hot" SCR on the simple cycle operation will have marginal overall air quality benefits given the proposed period of long-term operation (1,000 hours/year when combined cycle begins). Indeed, these have been recognized by EPA in evaluating DLN technology for combined cycle technology (EPA, 2000b). This includes the collateral impact resulting from ammonia emissions, formation of fine particulates, global warming and ammonia safety.

The use of DLN combustor technology is truly "pollution prevention" for simple cycle operation. The use of "Hot" SCR has associated primary and secondary environmental impacts. The electrical energy required to run the SCR system and the back pressure from the turbine will reduce the available power. The back pressure is a result of the amount of catalyst needed for the reduction and the velocity of exhaust gases. With simple cycle applications, the back pressure from "hot" SCR is about 4 inches of water gauge, significantly reducing the available power. This power, which would otherwise be available to the electrical system, will have to be replaced by other units. The replacement power will cause air pollutant emissions that would not have occurred without SCR. In addition, since the simple cycle unit provides peaking power, the replacement energy will be from much older and less efficient units, with much higher emission rates. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted.

Proposed NO_x BACT

The proposed BACT for simple cycle operation is based on emission rates using advanced DLN combustion technology when firing natural gas and water injection when firing distillate oil. The proposed NO_x emissions level using this DLN technology is 9 ppmvd corrected to 15-percent O_2 when firing natural gas. The NO_x emissions rate when oil firing will be controlled using water injection to 42 ppmvd corrected to 15-percent O_2. This combination of the technology can achieve the maximum amount of emission reduction available, is technically feasible and demonstrated for the limited amount of simple cycle operation proposed for the Project. SCR is rejected based on the technical feasibility, and economic, environmental, and energy impacts. Moreover, the simple cycle operation will be limited after combined cycle in operational. In combined cycle configuration, SCR has been determined to be technical feasible and cost effective. The proposed BACT is consistent with recent BACT decisions on other similar projects.

"Hot" SCR is rejected for the following reasons:

- SCR has not been demonstrated on an "F" Class dual fuel turbine. Applications of this technology on much smaller turbines have not been successful. SCR is considered technically infeasible for the Project.
- The estimated incremental cost of "Hot" SCR is approximately 10 times higher on a $ per ton of NO_x removed basis, than SCR applied to combined cycle. Similar costs for other projects that have rejected "Hot" SCR as being unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered.
- The energy impacts of SCR will reduce potential electrical power generation much greater than that for combined cycle (about 70% greater). This amount of energy is sufficient to provide greater electrical power for residential customers. Moreover, simple cycle operation will only be used when power demands are high (first year) or when combined cycle becomes inoperative. Peaking energy supplied by more efficient and lower polluting units will benefit the environment.
- The proposed BACT (i.e., DLN combustion) provides the most cost effective control alternative for simple cycle operation, is pollution preventing, and results in low environmental impacts (less than the significant impact levels). DLN combustion at the proposed emissions levels has been adopted in BACT determinations for simple cycle projects.

4.3.4 CARBON MONOXIDE

Technology Description

Emissions of CO are dependent on the combustor design, which is a result of the manufacturer's operating specifications, including the air-to-fuel ratio, staging of combustion, and the amount of water injected. The CTs proposed for the Project have designs to optimize combustion efficiency and minimize NO_x emissions to the lowest achievable using DLN combustion technology while maintaining low CO emission levels.

For the Project, the following alternatives were evaluated as BACT:

1. Combustion controls, and
2. Oxidation catalyst at 2 ppmvd emission rate.

There are two alternatives for installing an oxidation catalyst. The first would be to install a catalyst prior to the HRSG to reduce CO emissions from the turbine. This would result in the CO emissions from the duct burners being uncontrolled. The second alternative is to install an oxidation catalyst or $SCONO_x$™ within the HRSG. This would control all the CO emissions, including CO from the duct burners. The capital cost for an oxidation catalyst and its technical feasibility is not different when considering simple or combined cycle operation

Impact Analysis

Economic--The estimated capital cost for an oxidation catalyst installed in the HRSG is $1.64 million. The annualized cost of a CO oxidation catalyst is $691,000. The resulting cost effectiveness is approximately $4,165 per ton of CO removed for gas and oil firing. No costs are associated with combustion techniques, since they are inherent in the design.

$SCONO_x$™ also reduces CO emissions. The incremental cost effectiveness for CO removal for this system is over $20,000 per ton. This is based on the differential between the annualized cost of $SCONO_x$™ ($5.3 million) and SCR ($1.1 million) and the tons of CO potentially removed in the $SCONO_x$™ system.

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. Moreover, the air quality impacts, at the proposed CT emission rate, are predicted to be much less than the PSD significant impact levels. The maximum CO impacts are less than 0.1 percent of the applicable AAQS. There would also be no secondary benefits, such as reductions in O_3 precursors and acidic deposition, to reducing CO.

In contrast, the installation of an oxidation catalyst would create additional back pressure on the turbine that will result in lost electric generation that would otherwise be available and thus replaced by older, less efficient technology. The end result is an additional 1,970 TPY of carbon dioxide (CO_2). The ultimate end product of CO is CO_2, regardless of whether the process results from an oxidation catalyst or in the atmosphere. The lost energy caused by the back pressure from the oxidation catalyst would result in the generation of 10 times more greenhouse gases than the amount of CO converted to CO_2 in the oxidation catalyst.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 1.5 to 2 inches of water gauge would be expected. A catalyst back pressure of 2 inches would result in an energy penalty of about 3 million kWh/yr. The energy penalties are sufficient to supply the electrical needs of about 252 residential customers for a year. To replace this lost energy, about 3.1 x 10^{10} Btu/yr or about 31 million ft^3/yr of natural gas would be required. In contrast, the total energy requirements of $SCONO_x$™ is 36.3 x 10^{10} Btu/yr or about 363 million ft^3/yr of natural gas.

Proposed BACT and Rationale

Combustion design is proposed as BACT, as there are adverse technical and economic consequences of using catalytic oxidation on CTs. The proposed BACT emission rates for CO will not exceed 9 ppmvd when firing natural gas at baseload to 50-percent load (simple and combined cycle), 22.9 ppmvd when firing natural gas with duct firing (combined cycle) and 20 ppmvd when firing distillate oil (simple and combined cycle). Catalytic oxidation is considered unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts,
2. The economic impacts are significant (i.e., the capital cost is $1.64 million, with an annualized cost of about $691,000 per year per unit), and
3. Recent projects in Florida and Region IV have been authorized with BACT emission limits of similar magnitude.

$SCONO_x$™ is rejected as BACT based on the high differential costs of the technology. Also, the as described in the BACT evaluation for NO_x, the use of $SCONO_x$™ on a "F" Class turbine has associated technical uncertainty, as well as significant energy and environmental impacts.

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 produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for similar advanced CTs have set limits in the 9- to 25-ppmvd range when firing natural gas and distillate oil. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

The cost effectiveness calculations are significantly understated if the actual emission performance is considered. The actual CO emissions performance of the GE Frame 7FA turbines is much less than the guaranteed rates. This is a direct result of turbine manufacturers and duct burner vendors including significant margins on emissions of CO and VOCs to assure that NO_x emission guarantees can be achieved in the combustion systems. CO test data indicated that emissions range from 0.0 to 1.01 ppmvd (corrected to 15-percent O_2) with and average of 0.25 ppmvd (corrected to 15-percent O_2) when firing natural gas over loads from 50 percent to 100 percent. These data were from 67 tests. The GE guarantee is equivalent to 7.4 ppmvd corrected to 15-percent O_2 (i.e., 9 ppmvd) when firing natural gas. The actual CO emissions over 10 times less than the guarantee emission level.

4.3.5 PM/PM_{10}, SO_2, AND SULFURIC ACID MIST

The PM/PM_{10} emissions from the CTs are a result of incomplete combustion and trace elements 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 gas-fired or distillate oil-fired CTs.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs. The grain loading associated with the maximum particulate emissions (less than 20 lb/hr when firing natural gas) 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.

There are no technically feasible methods for controlling the emissions of SO_2 and sulfuric acid mist from CTs, other than the inherent quality of the fuel. The use of flue gas desulfurization (FGD) systems are not available, technically feasible, demonstrated or cost effective on CTs using natural gas. The use of natural gas, a clean fuel, represents BACT and will limit emissions of SO_2.

4.3.6 VOLATILE ORGANIC COMPOUNDS

VOCs will be emitted by the CTs as a result of incomplete combustion. The proposed emission rates for VOC emissions will be the use of combustion technology and the use of clean fuels so that emissions when firing natural gas will not exceed 1.5 ppmvd when firing natural gas at baseload and 7.0 ppmvd when duct firing. When firing distillate oil the emissions will not exceed 3.5 ppmvd. This emission level is similar to the BACT emission levels established for other similar sources. Combustion controls and the use of clean fuels have been overwhelmingly approved as BACT for CTs. The environmental effect of further reducing emissions would not be significant.

A review of the BACT/LAER Information System (BLIS) did not indicate any oxidation catalysts on natural gas fired combustion turbines to limit emissions of VOCs. A vendor of oxidation catalysts was contacted to determine the removal of VOCs in an oxidation catalyst typically used (i.e., primarily used for CO in nonattainment areas as LAER). The vendor stated that the typical VOC removal in a turbine application is from 30 to 40 percent. The cost effectiveness calculation is presented below:

VOC Cost Effectiveness Calculations

2.74	lb/hr gas firing at baseload
11.54	lb/hr gas firing at baseload w/duct firing
7.28	lb/hr oil firing
25.81	TPY
40.00%	removal
10.32	TPY removal
$66,936	per ton VOC removed
90.00%	removal
23.22738	TPY removed
$29,749	per ton VOC removed

At 40-percent VOC removal the cost effectiveness of an oxidation catalyst is over $66,000 per ton of VOC removed. Assuming that 90 percent reduction were available at the same cost, the cost effectiveness is over $29,000 per ton of VOC removed.

Similar to the results for CO, the actual VOC emission rates have been extremely low when compared with the emission guarantees. VOC test data indicated that emissions range from 0.0 to 1.65 ppmvd (corrected to 15-percent O_2) with and average of 0.23 ppmvd (corrected to 15-percent O_2) when firing natural gas over loads from 50 to 100 percent. These data were from 34 tests. The GE guarantee is 1.3 ppmvd (corrected to 15-percent O_2). The actual VOC emissions are 5 times lower than the guarantee emission level. Test results for duct firing with natural gas suggest that VOC emission rates remain unchanged.

4.3.7 GAS HEATERS

The emissions from these units are a result of incomplete combustion and trace elements in the fuel. There are no technically feasible methods for controlling emissions other than the inherent quality of the fuel (i.e., natural gas, diesel fuel oil). BACT proposed for the gas heaters is based on limiting annual hours of operation as indicated in the application.

4.3.8 COOLING TOWER

For the cooling tower, the installation of drift eliminators is the only feasible technology for controlling PM emissions. Drift eliminators use inertial separation caused by airflow direction changes to remove water droplets from the air stream exhausting from the cooling tower. These water droplets generally contain the same concentration of dissolved solids and chemical impurities as the water circulating through the tower and can be converted to airborne emissions.

Drift eliminator configurations include cellular (or honeycomb), wave-form, and herringbone (blade-type) designs. Drift eliminators may include various materials such as wood installed or formed into closely spaced slats, sheets, honeycomb assemblies, or tiles; ceramics, fiberglass, metal, and plastic.

Particulate emissions from the Project's cooling tower will be controlled utilizing high-efficiency drift eliminators achieving a drift loss rate of 0.002 percent of the cooling tower recirculating water flow.

Table 4-1. Proposed BACT Emission Limitations and Compliance Methods For Each CT/HRSG Unit

Pollutant	Emission Rate (Basis[a])	Conditions[b]	Compliance Method Proposed
Particulate Matter	9 / 17.2 lb/hr	SC/CC Gas Firing	VE < 10%
Sulfur Dioxide	17 / 37.8 lb/hr	SC/CC Oil Firing	VE < 20%
	10.2 / 13.3 lb/hr	SC/CC Gas Firing	Pipeline Natural Gas
	103.1 lb/hr	SC/CC Oil Firing	Distillate Oil (0.05-percent maximum sulfur)
Nitrogen Oxides	9 / 2.5 ppmvd corrected to 15-percent O_2	SC/CC Gas Firing	EPA Method 7E Initial Test; CEM 24-hour Block Average
	42 / 12 ppmvd corrected to 15-percent O_2	SC/CC Oil Firing	EPA Method 7E Initial Test; CEM 24-hour Block Average
Carbon Monoxide	9 ppmvd	SC/CC Gas Firing no DB	EPA Method 10
	24.5 ppmvd	CC Gas Firing with DB	EPA Method 10
	29.5 ppmvd	CC Gas Firing HPM/DB	EPA Method 10
	20 ppmvd	SC/CC Oil Firing	EPA Method 10
Volatile Organic Compounds	1.5 ppmvw	SC/CC Gas Firing no DB	EPA Methods 18, 25, or 25a
	7 ppmvw	CC Gas Firing with DB	EPA Methods 18, 25, or 25a
	3.5 ppmvw	SC/CC Oil Firing	EPA Methods 18, 25, or 25a

[a] Based on maximum emission rate over turbine inlet operating conditions.
[b] Operating loads from 50 to 100 percent.

Note:
CC = combined cycle.
DB = duct burner.
HPM = higher power mode.
ppmvd = parts per million, volume dry.
ppmvw = parts per million, volume wet.
SC = simple cycle.

5.0 AMBIENT MONITORING ANALYSIS

The CAA requires that an air quality analysis be conducted for each criteria and noncriteria pollutant subject to regulation under the act before a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Noncriteria pollutants are those pollutants that may be regulated by emission standards, but no AAQS have been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Based on the estimated emissions from the Project (see Table 3-3), pre-construction ambient monitoring analyses for SO_2, PM_{10}, NO_2, CO, ozone (based on VOC emissions) and sulfuric acid mist are required to be submitted as part of the application. The ambient monitoring analysis is not required if it can be demonstrated that the proposed source's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels and, for ozone (based on VOC emissions), VOC emission level of 100 TPY.

As shown in Table 3-4, the proposed Project's impacts are predicted to be below the *de minimis* monitoring concentrations when the Project is operating in simple cycle configuration. When the Project is operating in combined cycle configuration, the Project's impacts are also predicted to be below the applicable *de minimis* monitoring concentrations. In the case of ozone, the Project's VOC emissions are greater than the monitoring emission level of 100 TPY. Therefore, pre-construction ambient monitoring analyses for ozone (based on VOC emissions) are required to be submitted as part of the application.

For sulfuric acid mist, which is a noncriteria pollutant, although the Project's emissions are greater than the significant emission rate, EPA has established no acceptable monitoring method for this pollutant.

As a result, ambient ozone monitoring data from existing monitoring stations operated by FDEP are included in this application to satisfy the pre-construction monitoring requirement. Martin County and adjacent counties are classified as attainment for ozone. There are no ozone monitors located in Martin County. The nearest monitor to the Project that measures ozone concentrations is located at Fort Pierce in St. Lucie County (AIRS No. 12-111-0012), located approximately 50 km to the northeast of the Project. Since ozone is a regional pollutant, ozone monitoring data collected in St. Lucie County are considered to be representative of ozone concentrations for the region and is used to satisfy this requirement for the Project. This station is operated by the FDEP and measure concentrations according to EPA procedures.

From 1998 through July 2001, the second-highest 1-hour average ozone concentration measured at this site was 0.095 ppm. This maximum concentration is less than the existing 1-hour average ozone AAQS of 0.12 ppm. In addition, the 3-year average of the 4th highest 8-hour average ozone concentration was 0.073 ppm that is below the proposed 8-hour average ozone AAQS of 0.08 ppm. These O_3 monitoring data are proposed as part of this construction permit application to satisfy the preconstruction monitoring requirement for the project.

Therefore, based on the existing ozone ambient data and lack of an acceptable monitoring method for sulfuric acid mist, an exemption from the preconstruction monitoring requirement for ozone and sulfuric acid mist in accordance with the PSD regulations is appropriate.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 SIGNIFICANT IMPACT ANALYSIS APPROACH

6.1.1 SITE VICINITY

The general modeling approach followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the EPA significant impact levels at any location beyond the plant's restricted boundaries.

If the project-only impacts are above the significant impact levels in the vicinity of the facility, then two additional and more detailed air modeling analyses are required. The first analysis demonstrates compliance with federal and Florida ambient air quality standards (AAQS), and the second analysis demonstrates compliance with allowable PSD Class II increments.

6.1.2 PSD CLASS I AREAS

Generally, if the facility undergoing the modification is within 200 kilometers of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impact due to the project alone at the PSD Class I area. The PSD Class I area of Everglades NP is located approximately 144 km from the Project. Because Everglades NP is located within 200 km of the Project, the maximum predicted impacts at the Everglades NP are compared to EPA's proposed significant impact levels for PSD Class I areas. These recommended levels have never been promulgated as rules but are the currently accepted criteria to determine whether a proposed project will incur a significant impact on a PSD Class I area.

If the project-only impacts at the PSD Class I area are above the proposed EPA PSD Class I significant impact levels, then an analysis is performed to demonstrate compliance with allowable PSD Class I impacts at the PSD Class I area.

In addition, the project's maximum concentrations are evaluated at the PSD Class I area for pollutants whose emissions are greater than the significant emission rate, to address potential impacts on air quality related values (AQRV). This analysis includes an evaluation of regional haze degradation.

6.2 PRE-CONSTRUCTION MONITORING ANALYSIS APPROACH

The modeling approach followed EPA and FDEP modeling guidelines for evaluating a project's impacts relative to the *de minimis* monitoring levels to determine the need to submit ambient monitoring data prior to construction. Current FDEP policies stipulate that the predicted highest annual average and highest short-term concentrations are to be compared to the applicable *de minimis* monitoring levels.

6.3 AIR MODELING ANALYSIS APPROACH

6.3.1 GENERAL PROCEDURES

As stated in the previous sections, for each pollutant which is emitted above the significant emission rate, air modeling analyses are required to determine if the Project's impacts are predicted to be greater than the significant impact levels and *de minimis* monitoring levels. These analyses consider the Project's impacts alone. Air quality impacts are predicted using 5 years of meteorological data and selecting the highest predicted ground-level concentrations for comparison to the significant impact levels and *de minimis* monitoring levels.

To predict the maximum annual and short-term concentrations for the proposed Project, the modeling approach was divided into screening and refined phases. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record. If the highest concentration is predicted at a receptor that lies in an area where the receptor spacing is more than 100 m, then a refined analysis is performed in that area using a receptor grid of greater resolution. Modeling refinements are performed using a receptor spacing of 100 m or less with a receptor grid centered on the screening receptor at which the maximum concentration was predicted. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred.

If the Project's impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations to predict a total concentration for comparison to AAQS. Because the proposed Project's maximum 24-hour SO_2 impacts are predicted to be greater than the significant impact level, additional AAQS and PSD Class II Increment analyses were performed for this pollutant and averaging time.

Generally, when using 5-years of meteorological data for the analysis, the highest annual and the highest, second-highest (HSH) short-term concentrations are compared to the applicable AAQS and allowable PSD increments. [Note that for determining compliance with the 24-hour AAQS for PM_{10}, the sixth highest predicted concentration in five years (i.e., H6H), instead of the HSH, is used to compare to the applicable 24-hour AAQS.]

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.

The HSH approach is consistent with air quality standards and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

The AAQS analysis is a cumulative source analysis that evaluates whether the concentrations from all sources will comply with the AAQS. These concentrations include the modeled impacts from sources at the project site and from other nearby facility sources added to a background concentration. The background concentration accounts for sources not included in the modeling analysis.

The PSD Class II analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources will comply with the allowable PSD Class II increments. These concentrations include the modeled impacts from PSD increment-affecting sources at the project site, plus nearby PSD increment-affecting sources at other facilities.

6.3.2 PSD CLASS I ANALYSIS

For each pollutant for which a significant impact is predicted at the PSD Class I area, a PSD Class I analysis is required. The PSD Class I analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources located within 200 km of the PSD Class I area will comply with the allowable PSD Class I increments. These concentrations include the impacts from PSD increment-affecting sources at the project site, plus the impacts from PSD increment-affecting sources at other facilities.

6.4 MODEL SELECTION

The selection of an air quality model to calculate air quality impacts for the Project was based on its applicability to simulate impacts in areas surrounding the Project as well as at the PSD Class I area of interest. Two air quality dispersion models were selected and used in these analyses to address air quality impacts for the Project. These models were:

- The Industrial Source Complex Short Term (ISCST3) dispersion model, and
- The California Puff model (CALPUFF)

The ISCST3 (Version 00100) dispersion model (EPA, 2000) was used to evaluate the pollutant impacts due to the Project in nearby areas surrounding the Site. This model is maintained by the EPA on its internet website, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of ISCST3 model features is presented in Table 6-1. The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological data (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The ISCST3 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. These areas are referred to as simple terrain. The model can also be applied in areas where the terrain exceeds the stack heights. These areas are referred to as complex terrain.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The ISCST3 model can be executed in the rural or urban land use mode that affects stability dispersion coefficients, wind speed profiles, and mixing heights. Land use can be characterized based on a scheme recommended by EPA (Auer, 1978). If more than 50 percent land use within a 3-km radius around a project is classified as industrial or commercial, or high-density residential, then the urban option should be selected. Otherwise, the rural option is appropriate. Based on the land-use within a 3-km radius of the Project, the rural dispersion coefficients were used in the modeling analysis. Also, since the terrain around the facility is flat to gently rolling, the simple terrain feature of the model was selected. The ISCST3 model was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times.

At distances beyond 50 km from a source, the CALPUFF model, Version 5.4 (EPA, 2000), is recommended for use by the EPA and the Federal Land Manager (FLM). The CALPUFF model is a long-range transport model applicable for estimating the air quality impacts in areas that are more than 50 km from a source. The CALPUFF model is maintained by the EPA on the SCRAM internet website. The methods and assumptions used in the CALPUFF model are based on the latest recommendations for modeling analysis as presented in the following reports:

- The Interagency Workgroup on Air Quality Models (IWAQM), *Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998); and
- The *Federal Land Manager's Air Quality Relative Values Workgroup (FLAG) Phase I Report* (December, 2000).

In addition, updates to the modeling methods and assumptions were followed based on discussion with the FLM.

The CALPUFF model was used to perform a significant impact analysis for the Project at the PSD Class I area of Everglades NP and to assess the Project's impact on regional haze and total nitrogen and sulfur deposition levels. A more detailed description of the assumptions and methods used for the CALPUFF model is presented in Table 6-2 and in Appendix C.

6.5 METEOROLOGICAL DATA

Meteorological data used in the ISCST3 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) office located at the Palm Beach International Airport (PBI). The 5-year period of meteorological data was from 1987 through 1991. The NWS office at PBI is located approximately 45-km southeast of the site and is the closest primary weather station to the study area considered to have meteorological data representative of the project site. The PBI station meteorological data have been approved by the FDEP and used for numerous air modeling studies submitted as part of air construction permits approved for sources located in Palm Beach County.

CALMET, the meteorological preprocessor to CALPUFF, was used to develop a 3-dimensional wind field necessary to perform the air modeling analysis to evaluate pollutant impacts at each PSD Class I area. The modeling domain consisted of a rectangular 3-dimensional grid that extended from approximately 79.0 to 83.5 degrees longitude and from 23.75 to 28.0 degrees latitude. The modeling domain includes the following meteorological and land use parameters:

- Surface weather data,

- Upper air data,
- A 1-degree land use data,
- A 1-degree Digital Elevation Model (DEM) terrain data,
- Mesoscale Model - Generation 4 (MM4) data (for initializing the wind field), and
- Hourly precipitation data.

These data were obtained and processed for the calendar year 1990, the year for which MM4 data are available on CD. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the FLMs. Meteorological data used with the CALPUFF model consist of a CALMET-developed wind field covering south Florida. More detailed descriptions of the assumptions and methods used for processing the meteorological data and establishing the model domain are presented in Appendix C.

6.6 EMISSION INVENTORY

6.6.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the criteria pollutant emission rates, physical stack and stack operating parameters for the proposed CTs, operating in combined- and simple-cycle configurations, that were used in the air modeling analysis are presented in Tables 2-1 through 2-4. The emission and stack operating parameters presented are for 3 operating loads and 35°F, 59°F and 95°F ambient temperatures for the CTs firing natural gas and oil. Additional operating cases were also considered that included power augmentation and high power mode for the CTs firing natural gas. In an effort to obtain the maximum air quality impacts for a range of possible operating conditions, the air modeling used a range of emission rates and stack parameter data to predict air quality impacts.

A total of 21 modeling scenarios were considered for simple-cycle configuration with the CTs operating for the following conditions:

- CTs firing natural gas for ambient temperatures of 35, 59, and 95°F at:
  - 100 percent operating load
  - 75 percent operating load
  - 50 percent operation load
  - High Power Mode
- CTs firing oil for ambient temperatures of 35, 59, and 95°F at:
  - 100 percent operating load

- — 75 percent operating load
- — 50 percent operation load

A total of 21 modeling scenarios were considered for combined-cycle configuration with the CTs operating for the following conditions:

- CTs firing natural gas for ambient temperatures of 35, 59, and 95°F at:
  - — 100 percent operating load with duct firing
  - — 75 percent operating load
  - — 50 percent operation load
  - — power augmentation load with duct firing
- CTs firing oil for ambient temperatures of 35, 59, and 95°F at:
  - — 100 percent operating load
  - — 75 percent operating load
  - — 50 percent operation load

The proposed CTs will have a HRSG stack height of 120 ft and an inner stack diameter of 19 ft and a bypass stack height of 80 feet with and inner stack diameter of 22 ft. Because the proposed stack heights are less than GEP, building downwash effects were included in the modeling analysis (see following section on building downwash). The relative locations of the stacks used in the modeling analysis were:

Stacks	Relative Location (m) X	Y
HRSG Stack No. A	-152.7	55
HRSG Stack No. B	-107.1	55
HRSG Stack No. C	0	55
HRSG Stack No. D	45.7	55
Bypass Stack No. A	-152.7	0
Bypass Stack No. B	-107.1	0
Bypass Stack No. C	0	0
Bypass Stack No. D	45.7	0

The air modeling origin was assumed to be located at Bypass Stack C, which is located a UTM east and north coordinates of 543100 and 2992900 m, respectively, in UTM Zone 18.

The ISCST3 model was used to predict maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times. To estimate impacts due to emissions from the stacks, an emission rate of 79.365 pounds per hour (lb/hr) or 10 grams per second (g/s) was initially used to produce relative concentrations as a function of the modeled emission rate (i.e., $\mu g/m^3$ per 10 g/s). These impacts are referred to as generic pollutant impacts. Maximum air quality impacts for specific pollutants were then determined by multiplying the maximum pollutant-specific emission rate in lb/hr (g/s) by the maximum predicted generic impact divided by 79.365 lb/hr (10 g/s).

For the PSD Class I area of the Everglades NP, concentrations were predicted for the Project for combined- and simple-cycle operation with the CALPUFF model based on the operating scenario with the maximum hourly emissions. For both natural gas- and oil-firing, maximum emissions are based on the CTs operating for baseload conditions at an ambient temperature of 35°F.

For the CTs operating in combined cycle mode and firing natural gas, the duct burner emissions are included. For simple cycle operation and natural gas-firing, the CTs are assumed to operate at higher power mode.

Annual average concentrations are based on the operating scenarios with the maximum hourly emissions for the following annual hours:

- For SO_2 and PM_{10}: combined cycle operation with natural gas- and fuel oil-firing for 8,260 and 500 hours, respectively;
- For NO_2: combined cycle operation with natural gas-firing for 7,760; simple cycle operation with natural gas- and fuel oil-firing for 500 hours each; and
- For CO: combined cycle operation with natural gas-firing for 8,760.

6.6.2 AAQS AND PSD CLASS II ANALYSES

As discussed in Section 6.10, the maximum impacts from the Project were predicted to be less than the significant impact levels for all pollutants, except SO_2 for the 24-hour averaging period. As a result a cumulative source analysis is required to demonstrate compliance with the 24-hour average SO_2 AAQS and PSD Class II increments.

A listing of background SO_2 sources used in the AAQS and PSD Class II modeling analyses and their locations relative to the Project is provided in Table 6-3. All facilities were evaluated using the North Carolina screening technique. Based on this technique, facilities whose annual (i.e., ton per year) emissions are less than the threshold quantity, Q, are eliminated from the modeling analysis. Q is equal to 20 x (D-SIA), where D is the distance in km from the facility to the Project and SIA is the distance of the proposed project's SO_2 significant impact area (9 km). The SO_2 facilities that were not eliminated in the screening analysis are available for inclusion in the AAQS and PSD Class II analyses.

Detailed SO_2 background source data that were used for the AAQS and PSD Class II analyses are presented in Appendix D. Non-Project SO_2 PSD sources were obtained from FDEP and were supplemented with current and historical information available within Golder.

6.6.3 PSD CLASS I ANALYSIS

Similar to the maximum Project impacts predicted in the Project's vicinity, the maximum Project impacts at the PSD Class I area of the Everglades NP are predicted to by less than the proposed Class I significant impact levels for all pollutants, except SO_2 for the 24-hour averaging period. As a result, a cumulative source impact analysis is required to demonstrate compliance with the 24-hour average SO_2 PSD Class I increment.

A listing of background SO_2 sources that were used in the PSD Class I analysis and their locations relative to the PSD Class I area of the Everglades NP is provided in Table 6-4. PSD sources located within 200 km of the Everglades NP were included in the PSD Class I modeling analysis. Detailed SO_2 background source data that were used for the PSD Class I analysis are presented in Appendix D.

6.7 <u>RECEPTOR LOCATIONS</u>

6.7.1 SITE VICINITY

To determine the maximum impact for all pollutants and averaging times in the Project's vicinity, concentrations were predicted at receptors located in a detailed polar receptor grid centered on the modeling origin. This grid was comprised of 180 radials, spaced at 2-degree intervals along each radial. Receptors were located at the following distances from the origin:

- Every 100 m out to 3 km;

- Every 250 m from 3 km to 7 km;
- Every 500 m from 7 km to 10 km; and
- Every 5,000 m from 10 km to 30 km.

Additionally, Cartesian receptors were placed every 50 m along the plant boundary. The Lakes Environmental ISC-Aermod View software program, Version 4.0, was utilized to produce the receptor grid and boundary receptors. Receptors located within the plant boundary (fence-line) were removed from the modeling receptor grid, since this area is restricted and not considered to be ambient air locations. In order to remove the plant receptors, the polar receptor grids were first converted to Cartesian coordinates, due to the procedures in the software program, see Appendix E for a graphical representation of the resulting receptor grid as well as an example input file for a detailed list of receptor points.

To determine the 24-hour average SO_2 significant impact area for the Project, a second receptor grid was developed using a polar receptor grid centered on the modeling origin. This grid was comprised of 180 radials, with receptors spaced at 2-degree intervals along each radial. Receptors were located every 1000 meters out to a distance of 15 km from the modeling origin. Additionally, 657 Cartesian receptors, spaced at 50 m, were used to predict impacts along the plant boundary. The receptor locations, along with the plant property boundary and the modeling origin, are shown in Appendix E.

6.7.2 CLASS I AREA

Maximum pollutant concentrations were predicted with the CALPUFF model using 126 discrete receptors located along the border of the PSD Class I area of the Everglades NP. These receptors were also used in the AQRV analysis to address the Project's impacts on regional haze and sulfur and nitrogen deposition. A listing of Class I receptors used in the modeling analysis is provided in Table 6-5.

6.8 BACKGROUND CONCENTRATIONS

To estimate total air quality 24-hour average SO_2 concentrations in the site vicinity, a background concentration must be added to the AAQS modeling results. The background concentration is considered to be the air quality concentration contributed by sources not included in the modeling evaluation.

For this analysis, the highest 24-hour average SO_2 concentration of 34 $\mu g/m^3$ measured for the past four years in Palm Beach County was used to represent background concentration. This concentration was obtained from a monitoring station operated by the FDEP in Riviera Beach (AIRS number 12-099-3004). This background level was added to model-predicted concentrations to estimate total air quality levels for comparison to AAQS.

6.9 BUILDING DOWNWASH EFFECTS

All significant building structures in the Project area were identified by the site plot plan (see Figure 2-2). The building structures were processed in the EPA Building Input Profile (BPIP, Version 95086) program to determine direction-specific building heights and widths for each 10-degree azimuth direction for each source that was included in the modeling analysis. A listing of dimensions for each structure is presented in Table 6-6. See Appendix E for plots of these building structures.

6.10 MODEL RESULTS

6.10.1 PSD CLASS II SIGNIFICANT IMPACT ANALYSIS

The maximum pollutant concentrations predicted for the Project by operating load and air inlet temperature for simple-cycle operation are given in Table 6-7. The maximum pollutant concentrations predicted for the Project by operating load and air inlet temperature for combined-cycle operation are given in Table 6-8. A summary of the predicted maximum SO_2, NO_x, CO, and PM_{10} concentrations predicted for the Project for the significant impact analysis is presented in Table 6-9. The modeling results indicated that maximum concentrations due to the Project are predicted to be less than the significant impact levels for all pollutants except SO_2 for the 24-hour averaging period. The significant impact area for the project's SO_2 concentrations extends out approximately 9 km for the Project. As a result, additional modeling analyses were performed for SO_2 to address compliance with AAQS and PSD increments.

6.10.2 AAQS ANALYSIS

A summary of the maximum HSH 24-hour average SO_2 concentrations predicted for all sources for the screening analysis is presented in Table 6-10. Based on the screening analysis results, modeling refinements were performed.

The maximum predicted HSH 24-hour SO_2 concentration is 109 $\mu g/m^3$. This concentration includes a non-modeled 24-hour background concentration of 34 $\mu g/m^3$. The maximum predicted HSH 24-hour average SO_2 concentration is below the Florida AAQS 260$\mu g/m^3$.

6.10.3 PSD CLASS II ANALYSIS

Summaries of the maximum SO_2 PSD increment consumption predicted for all sources for the screening analysis is presented in Table 6-11. Based on the screening analysis results, modeling refinements were performed.

The maximum predicted HSH 24-hour SO_2 increment consumption concentration of 41.4 $\mu g/m^3$, is less than the allowable PSD Class II increments of 91 $\mu g/m^3$.

6.10.4 PSD CLASS I INCREMENT ANALYSIS

The modeling analysis results for the Project at the Everglades NP are summarized in Table 6-12. When firing natural gas, the primary fuel, the maximum SO_2, PM_{10} and NO_2 pollutant concentrations are predicted to be well below the EPA proposed PSD Class I significant impact levels. When firing fuel oil, the maximum 24-hour average SO_2 concentrations were also predicted to be the EPA proposed PSD Class I significant impact levels for all pollutants, except SO_2 for the 24-hour average period. Therefore, a more detailed analysis for determining compliance with the 24-hour SO_2 PSD Class I increment was performed.

The results of the PSD Class I increment analysis are presented in Table 6-13. The highest, second-highest predicted 24-hour SO_2 concentration is 3.5 $\mu g/m^3$, which is below the allowable 24-hour PSD Class I increment of 5 $\mu g/m^3$.

6.10.5 CONCLUSIONS

Based on these air quality modeling analyses, the maximum pollutant concentrations due to the Project's emissions are predicted to be less than the PSD Class II and I significant impact levels for all pollutants except SO_2 for the 24-hour averaging period. As a result, more detailed SO_2 modeling analyses including offsite sources were performed for PSD Class II and I areas. The results of the modeling analysis demonstrate the Project will not have a significant affect on air quality and will comply with all applicable AAQS and PSD increments.

Table 6-1. Major Features of the ISCST3 Model

ISCST3 Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975; Bowers, et al., 1979).
• Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulman and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple emission sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, area, and open pit sources
• Capability to calculate dry and wet deposition, including both gaseous and particulate precipitation scavenging for wet deposition
• Variation of wind speed with height (wind speed-profile exponent law)
• Concentration estimates for 1 hour to annual average times
• Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm for ISCST3; a built-in algorithm for predicting concentrations in complex terrain
• 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 including setting wind speeds less than 1 m/s to 1 m/s.

Note: ISCST3 = Industrial Source Complex Short-Term

References:

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Schulman, L.L. and J.S. Scire. 1980. Buoyant Line and Point Source (BLP) Dispersion Model User's Guide. Document P-7304B, Environmental Research and Technology, Inc., Concord, MA.

Table 6-2. Major Features of the CALPUFF Model, Version 5.4

CALPUFF Model Features
• Source types: Point, line (including buoyancy effects), volume, area (buoyant, non-buoyant)
• Non-steady-state emissions and meteorological conditions (time-dependent source and emission data; gridded 3-dimensional wind and temperature fields; spatially-variable fields of mixing heights, friction velocity, precipitation, Monin-Obukhov length; vertically and horizontally-varying turbulence and dispersion rates; time-dependent source and emission data for point, area, and volume sources; temporal or wind-dependent scaling factors for emission rates)
• Efficient sampling function (integrated puff formulation; elongated puff (slug) formation)
• Dispersion coefficient options (Pasquill-Gifford (PG) values for rural areas; McElroy-Pooler values (MP) for urban areas; CTDM values for neutral/stable; direct measurements or estimated values)
• Vertical wind shear (puff splitting; differential advection and dispersion)
• Plume rise (buoyant and momentum rise; stack-tip effects; building downwash effects; partial plume penetration above mixing layer)
• Building downwash effects (Huber-Snyder method; Schulman-Scire method)
• Complex terrain effects (steering effects in CALMET wind field; puff height adjustments using ISC model method or plume path coefficient; enhanced vertical dispersion used in CTDMPLUS)
• Subgrid scale complex terrain (CTSG option) (CTDM flow module; dividing streamline as in CTDMPLUS)
• Dry deposition (gases and particles; options for diurnal cycle per pollutant, space and time variations with a resistance model, or none)
• Overwater and coastal interaction effects (overwater boundary layer parameters; abrupt change in meteorological conditions, plume dispersion at coastal boundary; fumigation; option to use Thermal Internal Boundary Layers (TIBL) into coastal grid cells)
• Chemical transformation options (Pseudo-first-order chemical mechanisms for SO_2, SO_4, HNO_3, and NO_3; Pseudo-first-order chemical mechanisms for SO_2, SO_4, NO, NO_2, HNO_3, and NO_3 (RIVAD/ARM3 method); user-specified diurnal cycles of transformation rates; no chemical conversions)
• Wet removal (scavenging coefficient approach; removal rate as a function of precipitation intensity and type)
• Graphical user interface
• Interface utilities (scan ISCST3 and AUSPLUME meteorological data files for problems; translate ISCST3 and AUSPLUME input files to CALPUFF input files

Note: CALPUFF = California Puff Model
Source: EPA, 2000.

Table 6-3. Summary of SO_2 Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to FPL Martin Plant [a] X (km)	Y (km)	Distance (km)	Direction (deg)	Maximum SO_2 Emissions (TPY)	Q, Emission Threshold [b] (Dist - SIA) x 20	Include in Modeling Analysis ?
0850102	Bechtel Indiantown	Martin	545.6	2991.5	2.5	-1.4	2.9	119	2,629	SIA	YES
0990021	Pratt & Whitney	Palm Beach	559.2	2978.3	16.1	-14.6	21.7	132	504	254.7	YES
0990019	Osceola Farms	Palm Beach	544.2	2968.0	1.1	-24.9	24.9	177	2,023	318.5	YES
0990061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-4.3	-24.8	25.2	190	2,698	323.4	YES
0850021	Stuart Contracting	Martin	575.2	3006.8	32.1	13.9	35.0	67	100	519.6	NO
0990026	Sugar Cane Growers	Palm Beach	534.9	2953.3	-8.2	-39.6	40.4	192	2,555	628.8	YES
0990086	Glades Correctional Institute	Palm Beach	523.4	2955.2	-19.7	-37.7	42.5	208	98	670.7	NO
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	9.8	-47.7	48.7	168	954	793.9	YES
	Fort Pierce Utilities	St. Lucie	566.8	3036.3	23.7	43.4	49.4	29	2,708	809.0	YES
0510001	Everglades Sugar	Hendry	509.6	2954.2	-33.5	-38.7	51.2	221	1,216	843.7	YES
0510003	U.S. Sugar Clewiston	Hendry	506.1	2956.9	-37.0	-36.0	51.6	226	7,806	852.5	YES
0990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	42.7	-32.7	53.8	127	1,533	895.7	YES
	Okeelanta	Palm Beach	525.0	2937.4	-18.1	-55.5	58.4	198	939	987.5	NO
0990042	FPL -Riviera Beach[c]	Palm Beach	594.2	2960.6	51.1	-32.3	60.5	122	73,475	1029.0	YES
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	-55.5	-35.3	65.8	238	409	1135.5	NO
	Vero Beach Power [c]	St. Lucie	567.1	3056.5	24.0	63.6	68.0	21	11,832	1179.6	YES
0990568	Lake Worth Utilities[c]	Palm Beach	592.8	2943.7	49.7	-49.2	69.9	135	8,996	1218.7	YES
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	40.5	-85.3	94.4	155	896	1708.5	NO

Note: deg = degrees
km = kilometers
SIA = significant impact area
TPY = tons per year

[a] FPL Martin Plant's East and North Coordinates (km) are: 543.1 and 2992.9 , respectively.

[b] Based on North Carolina Screening Technique for annual average basis. "Dist" is the distance the facility is located from the project. "SIA" is the significant impact area. The project's 24-hour SO_2 concentrations are predicted to be significant out to 9 km from the project.

[c] Large source with annual emissions greater than 1,000 TPY located beyond the screening area (59 km) that were included in the inventory.

Table 6-4. Summary of SO_2 Facilities Included in the PSD Class I Air Modeling Analysis

AIRS Number	Facility	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Everglades National Park x (km)	y (km)	Distance [a] (km)	Direction (deg)
0250348	Dade Co. Resource Recovery	Dade	564.3	2857.4	14.3	8.8	16.8	58
0250020	Tarmac	Dade	562.9	2861.7	12.9	13.1	18.4	45
0112119	South Broward Resource Recovery	Broward	579.6	2883.3	29.6	34.7	45.6	40
0110037	FPL -Lauderdale	Broward	580.1	2883.3	30.1	34.7	45.9	41
0110120	North Broward Resource Recovery	Broward	583.6	2907.6	33.6	59.0	67.9	30
0710019	Lee County Resource Recovery	Lee	424.0	2946.0	-30.0	82.8	88.1 [b]	340
0990332	Okeelanta	Palm Beach	525.0	2937.4	-25.0	88.8	92.3	344
0710000	FPL - Fort Myers	Lee	422.1	2952.9	-31.9	89.7	95.2 [b]	340
0990016	Atlantic Sugar	Palm Beach	552.9	2945.2	2.9	96.6	96.6	2
0990568	Lake Worth Utilities	Palm Beach	592.8	2943.7	42.8	95.1	104.3	24
0990026	Sugar Cane Growers Coop.	Palm Beach	534.9	2953.3	-15.1	104.7	105.8	352
0510003	U.S. Sugar Clewiston	Hendry	506.1	2956.9	-43.9	108.3	116.9	338
0990234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	35.8	111.6	117.2	18
0990019	Osceola Farms	Palm Beach	544.2	2968.0	-5.8	119.4	119.5	357
0990061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-11.2	119.5	120.0	355
0510015	Southern Gardens Citrus	Hendry	487.6	2957.6	-62.4	109.0	125.6	330
0990021	Pratt & Whitney	Palm Beach	559.2	2978.3	9.2	129.7	130.0	4
0850102	Bechtel Indiantown	Martin	545.6	2991.5	-4.4	142.9	143.0	358
0850001	FPL -Martin	Martin	543.1	2992.9	-6.9	144.3	144.5	357

[a] Distance from the northeastern corner of the Everglades National Park, UTM East and North coordinates (km) of 550.0 and 2848.6 , respectively, unless noted.
[b] Distance from the northwestern corner of the Everglades National Park, UTM East and North coordinates (km) of 454.0 and 2863.2 , respectively.

Table 6-5. Receptors of the PSD Class I Area of the Everglades NP

UTM Coordinates (m)		UTM Coordinates (m)		UTM Coordinates (m)		UTM Coordinates (m)	
East	North	East	North	East	North	East	North
557000	2789000	538000	2848600	514500	2837000	470000	2860000
556600	2792000	537000	2848600	514500	2836000	469000	2860000
556000	2796000	536000	2848600	514500	2835000	468000	2860000
553000	2796500	535000	2848600	514500	2834000	467000	2860000
548000	2796500	534000	2848600	514500	2833000	466000	2860000
542700	2796500	533000	2848600	514500	2832500	465000	2860000
542700	2800000	532000	2848600	510000	2832500	464000	2860000
542700	2805000	531000	2848600	509000	2832500	463000	2860000
542700	2810000	530000	2848600	508000	2832500	462000	2860000
542000	2811000	529000	2848600	507000	2832500	461000	2860000
541300	2814000	528000	2848600	506000	2832500	460000	2860000
542700	2816000	527000	2848600	505000	2832500	459500	2863200
544100	2820000	526000	2848600	504000	2832500	459000	2863200
543500	2824600	525000	2848600	503000	2832500	458000	2863200
545000	2829000	524000	2848600	502000	2832500	457000	2863200
545700	2832200	523000	2848600	501000	2832500	456000	2863200
546200	2835700	522000	2848600	500000	2832500	455000	2863200
548600	2837500	521000	2848600	499000	2832500	454000	2863200
550300	2839000	520000	2848600	498000	2832500		
545000	2839000	519000	2848600	497000	2832500		
540000	2839000	518000	2848600	496000	2832500		
550500	2844000	517000	2848600	495000	2832500		
545000	2844000	516000	2848600	495000	2833000		
540000	2844000	515000	2848600	495000	2834000		
550300	2848600	514500	2848600	495000	2835000		
549000	2848600	514500	2848000	495000	2836000		
548000	2848600	514500	2847600	494500	2837000		
547000	2848600	514500	2846600	491500	2841000		
546000	2848600	514500	2845000	488500	2845500		
545000	2848600	514500	2844000	483000	2848500		
544000	2848600	514500	2843000	480000	2852500		
543000	2848600	514500	2842000	475000	2854000		
542000	2848600	514500	2841000	473500	2857000		
541000	2848600	514500	2840000	473000	2860000		
540000	2848600	514500	2839000	472000	2860000		
539000	2848600	514500	2838000	471000	2860000		

Note: FPL Martin Plant's UTM East and North coordinates are 543100 m, 2940100 m, repectively.
m = meter.

Table 6-6. Project Building Dimensions Used in the Modeling Analysis

Stucture	Height ft	Height m	Length ft	Length m	Width ft	Width m
CT Air Inlet A	45	13.72	48.3	14.72	24	7.3
CT Inlet Sructure A	66.5	20.27	10.5	3.2	44.6	13.6
HRSG Structure A	83	25.3	74.5	22.7	31	9.45
CT Air Inlet B	45	13.72	48.3	14.72	24	7.3
CT Inlet Sructure B	66.5	20.27	10.5	3.2	44.6	13.6
HRSG Structure B	83	25.3	74.5	22.7	31	9.45
CT Air Inlet C	45	13.72	48.3	14.72	24	7.3
CT Inlet Sructure C	66.5	20.27	10.5	3.2	44.6	13.6
HRSG Structure C	83	25.3	74.5	22.7	31	9.45
CT Air Inlet D	45	13.72	48.3	14.72	24	7.3
CT Inlet Sructure D	66.5	20.27	10.5	3.2	44.6	13.6
HRSG Structure D	83	25.3	74.5	22.7	31	9.45

Note: CT= combustion turbine; HRSG= heat recovery steam generator

Table 6-7. Maximum Pollutant Concentrations Predicted for the Project by Operating Load and Air Inlet Temperature for Simple Cycle Operation

		Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Inlet Temperature [a]										
	Averaging	Power Augmentation	Higher Power Mode	Baseload			75% Load			50% Load		
Pollutant	Time	80°F	95°F	95°F	59°F	35°F	95°F	59°F	35°F	95°F	59°F	35°F
Natural Gas Operation												
SO_2	Annual	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	24-Hour	0.09	0.09	0.09	0.09	0.10	0.09	0.09	0.10	0.08	0.09	0.09
	3-Hour	0.41	0.41	0.40	0.42	0.43	0.37	0.40	0.41	0.34	0.36	0.37
PM_{10}	Annual	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	24-Hour	0.09	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.13	0.13	0.13
NO_2	Annual	0.06	0.07	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
CO	8-Hour	1.08	1.07	0.63	0.66	0.68	0.64	0.67	0.68	0.61	0.65	0.66
	1-Hour	3.22	3.19	1.84	1.96	1.88	2.59	2.79	2.89	2.23	2.38	2.45
Fuel Oil Operation												
SO_2	Annual	NA	NA	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.07
	24-Hour	NA	NA	0.78	0.82	0.84	0.77	0.79	0.81	0.77	0.80	0.82
	3-Hour	NA	NA	3.91	4.13	4.23	3.62	3.92	4.05	3.25	3.46	3.55
PM_{10}	Annual	NA	NA	0.01	0.01	0.01	0.02	0.01	0.01	0.02	0.02	0.02
	24-Hour	NA	NA	0.15	0.14	0.14	0.18	0.17	0.17	0.23	0.22	0.21
NO_2	Annual	NA	NA	0.22	0.22	0.23	0.21	0.22	0.23	0.20	0.20	0.21
CO	8-Hour	NA	NA	1.31	1.38	1.42	1.25	1.30	1.34	1.23	1.27	1.29
	1-Hour	NA	NA	4.08	4.24	4.36	4.27	4.19	4.28	4.00	4.11	4.18

Note: NA = not applicable

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

Table 6-8. Maximum Pollutant Concentrations Predicted for the Project by Operating Load and Air Inlet Temperature for Combined Cycle Operation

Pollutant	Averaging Time	Power Augmentation 80°F	Baseload 95°F	Baseload 59°F	Baseload 35°F	75% Load 95°F	75% Load 59°F	75% Load 35°F	50% Load 95°F	50% Load 59°F	50% Load 35°F
		Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Inlet Temperature [a]									
Natural Gas Operation [b]											
SO_2	Annual	0.11	0.13	0.13	0.12	0.10	0.11	0.11	0.11	0.12	0.12
	24-Hour	1.60	1.76	1.78	1.76	1.29	1.33	1.37	1.31	1.38	1.42
	3-Hour	3.44	3.74	3.85	3.86	2.77	2.87	2.95	2.86	3.00	3.10
PM_{10}	Annual	0.15	0.19	0.17	0.16	0.15	0.14	0.14	0.20	0.19	0.19
	24-Hour	2.17	2.50	2.37	2.28	1.85	1.77	1.77	2.28	2.23	2.23
NO_2	Annual	0.27	0.34	0.33	0.32	0.24	0.25	0.25	0.26	0.27	0.28
CO	8-Hour	16.23	15.3	14.5	13.9	5.99	6.14	6.31	6.37	6.60	6.79
	1-Hour	38.88	31.4	32.3	31.7	12.3	13.3	13.8	17.9	19.1	19.6
Fuel Oil Operation											
SO_2	Annual	NA	0.40	0.39	0.38	0.48	0.50	0.51	0.55	0.60	0.62
	24-Hour	NA	6.67	6.62	6.46	7.41	7.72	7.83	7.72	8.38	8.64
	3-Hour	NA	14.4	14.6	14.6	15.8	16.7	17.0	15.6	16.9	17.5
PM_{10}	Annual	NA	0.16	0.14	0.14	0.21	0.21	0.21	0.27	0.28	0.29
	24-Hour	NA	2.62	2.48	2.37	3.24	3.23	3.20	3.83	3.97	4.01
NO_2	Annual	NA	0.37	0.36	0.35	0.44	0.46	0.46	0.50	0.54	0.56
CO	8-Hour	NA	6.81	6.72	6.61	7.27	7.58	7.71	7.87	8.30	8.49
	1-Hour	NA	17.5	19.0	19.9	16.3	17.4	18.0	18.0	19.0	19.5

Note: NA = not applicable

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

[b] Duct firing included for baseload operating load. Duct firing based on natural gas-fired duct burner with maximum heat input rate of 550 mmBtu/hr (HHV).

Table 6-9. Summary of Maximum Pollutant Concentrations Predicted for the Project, Compared to the EPA Class II Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m^3) Simple Cycle Natural Gas	Simple Cycle Fuel Oil	Combined Cycle Natural Gas	Combined Cycle Fuel Oil	EPA Class II Significant Impact Levels (ug/m^3)
CTs Only						
SO_2	Annual	0.01	0.07	0.13	0.62	1
	24-Hour	0.10	0.84	1.78	8.64	5
	3-Hour	0.43	4.23	3.86	17.5	25
PM_{10}	Annual	0.01	0.02	0.20	0.29	1
	24-Hour	0.13	0.23	2.50	4.01	5
NO_2	Annual	0.07	0.23	0.34	0.56	1
CO	8-Hour	1.08	1.42	16.2	8.49	500
	1-Hour	3.22	4.36	38.9	19.9	2,000
CTs and Cooling Tower						
PM_{10}	Annual	NM	NM	NM	0.34	1
	24-Hour	NM	NM	NM	4.37	5

Note: NM = not modeled.

Table 6-10. Maximum Predicted SO_2 Impacts For Comparison to AAQS- Screening and Refined Analyses

Rank and Averaging Time	Concentration (µg/m³) [a] Total	Modeled Sources	Background	Receptor Location [b] x (m)	y (m)	Time Period (YYMMDDHH)	AAQS (µg/m³)
Screening Analysis							
HSH 24-Hour	107	73	34	-4,145	2,796	87123124	260
	106	72	34	-3,786	2,344	88013024	
	97	63	34	-4,283	2,344	89060424	
	103	69	34	-4,233	2,344	90030824	
	108	74	34	-3,716	3,346	91040424	
Refined Analysis							
HSH 24-Hour	109	75	34	-3,800	3,300	91072424	260
	108	74	34	-4,000	2,800	87061924	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, Second-Highest

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

[b] Relative to Bypass Stack C.

Table 6-11. Maximum Predicted SO_2 Impacts For Comparison to the PSD Class II Increment- Screening and Refined Analyses

Rank and Averaging Time	Concentration ($\mu g/m^3$) [a] Modeled Sources	Receptor Location [b] x (m)	y (m)	Time Period (YYMMDDHH)	PSD Class II Increment ($\mu g/m^3$)
Screening Analysis					
HSH 24-Hour	41.4	-2,741	2,344	87123124	91
	36.2	-3,830	3,214	88013024	
	37.4	-1,996	2,344	89060424	
	38.8	-4,061	-1,729	90030824	
	38.0	-4,233	2,344	91040424	
Refined Analysis					
HSH 24-Hour	41.4	-2,741	2,344	87080724	91
	39.1	-4,600	-2,000	90030824	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, Second-Highest

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport.

[b] Relative to Bypass Stack C.

Table 6-12. Summary of Maximum Pollutant Concentrations Predicted for the Project at the PSD Class I Area of the Everglades NP Compared to the Proposed EPA Class I Significant Impact Levels

Pollutant	Averaging Time	Maximum Concentration ($\mu g/m^3$) [a]			Proposed EPA Class I Significant Impact Levels ($\mu g/m^3$)
		Natural Gas	Fuel Oil	Natural Gas/ Fuel Oil	
Combined-Cycle [b]					
SO_2	Annual [c]	NM	NM	0.0013	0.1
	24-Hour	0.052	0.388	0.388	0.2
	3-Hour	0.110	0.803	0.803	1.0
NO_2	Annual [c]	NM	NM	0.0017	0.1
PM_{10}	Annual [c]	NM	NM	0.0018	0.2
	24-Hour	0.086	0.174	0.174	0.3
Simple-Cycle [b]					
SO_2	Annual [c]	NM	NM	0.0013	0.1
	24-Hour	0.035	0.338	0.338	0.2
	3-Hour	0.074	0.716	0.716	1.0
NO_2	Annual [c]	NM	NM	0.0017	0.1
PM_{10}	Annual [c]	NM	NM	0.0018	0.2
	24-Hour	0.039	0.069	0.069	0.3

Note: NM = not modeled

[a] Concentrations are highest predicted using CALPUFF model and 1990 CALMET wind field for south Florida.

[b] Concentrations predicted for combined- and simple cycle operation are based on the operating scenario with the maximum hourly emissions. For both natural gas- and oil-firing, maximum emissions are based on the combustion turbines operating for baseload conditions at an ambient temperature of 35°F.

For combined cycle operation and natural gas-firing, duct burner emission are included. For simple cycle operation and natural gas-firing, combustion turbines are assumed to operate at higher power mode.

[c] Annual average concentrations are based on the operating scenarios with the maximum hourly emissions for the following annual hours:

1. For SO_2 and PM_{10}: combined cycle operation with natural gas- and fuel oil-firing for 8,260 and 500 hours, respectively; and
2. For NO_2: combined cycle operation with natural gas-firing for 7,760; simple cycle operation with natural gas- and fuel oil-firing for 500 hours each.

Table 6-13. Summary of the Maximum 24-hour Average SO_2 Concentration Predicted for PSD Sources at the PSD Class I Area of the Everglades NP Compared to the Allowable PSD Class I Increment

Averaging Time	Maximum Concentration [a] ($\mu g/m^3$)	Receptor Location (m) UTM East	UTM North	Period Ending (Julian day/ year)	Allowable PSD Class I Increments ($\mu g/m^3$)
24-Hour	3.50	534,000	2,840,600	317/1990	5

Note: UTM = Universal Transverse Mercator

[a] Second-highest concentration predicted with the CALPUFF model.

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 IMPACTS DUE TO ASSOCIATED DIRECT GROWTH

The Project is being constructed to meet current and projected electric demands. FPL has an obligation to meet this increase in electric demand. Additional growth as a direct result of the additional electric power provided by the Project is not expected.

Construction of the Project will occur over a 24-month period requiring an average of approximately 250 workers during that time. It is anticipated that many of these construction personnel will commute to the Site.

The Project will employ a total of 12 operational workers at Project build-out. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services. The workforce needed to operate the proposed Project represents a small fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated industrial/ commercial growth given the location at the existing Martin Plant. The existing commercial and industrial infrastructure should be adequate to provide any support services that the Project might require and would not increase with the operation of the Project. Since construction of Martin Units 3 and 4 in early 1990, the Indiantown area grew only about 10 percent over the last 10 years. The addition of the nominal 1,000-MW facility had little effect on the increase or growth in the area.

7.2 IMPACTS ON SOILS, VEGETATION, WILDLIFE AND VISIBILITY

The maximum air quality impacts for the Project predicted in the vicinity of the site were used to assess the Project's potential impacts on nearby soils, vegetation, wildlife and visibility.

According to the USDA Martin County Soil Survey, soils in the vicinity of the project are classified as Candler fine sand, an excessively drained, sloping soil found in the sandhill areas of Martin County. Excessively drained, sandy soils are by nature acidic, therefore agricultural uses require amendment of soil with lime to increase alkalinity.

Vegetative communities in the vicinity of the project site are primarily pine plantation, improved pasture, xeric oak hammock, and maintained lawns associated with the wastewater treatment plant and access road right-of-ways.

The Project's impacts on the local air quality are predicted to be less than the significant impact levels for PSD Class II areas, except for the 24-hour average SO_2 concentrations when the Project is operating in combined cycle mode and firing fuel oil. When modeled with background SO_2 emission sources, the total air quality impacts when the Project is operating in combined cycle mode and firing fuel oil are predicted to be less than 58 percent of the AAQS; the Project's impacts are less than 3 percent of the AAQS. Since the AAQS are designed to protect the public welfare, including effects on soils and vegetation, and the Project's impacts are predicted to be generally less than the significant impact levels, no detrimental effects on soils or vegetation should occur in this area due to the Project's operation.

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion (Newman, 1980). Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutants levels.

It is unlikely that the Project's emissions will cause injury or death to wildlife based on a review of the limited literature on air pollutant effects on wildlife. The Project's impacts are predicted to be very low and dispersed over a large area. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the Project's impacts under weather conditions that lead to high concentrations is extremely unlikely.

In addition, no visibility impairment in the Project's vicinity is expected due to the types and quantities of emissions proposed for the Project. The opacity of the proposed exhaust emissions for both simple and combined cycle operation will be 10 percent or less.

7.3 IMPACTS TO PSD CLASS I AREAS

7.3.1 IDENTIFICATION OF AQRVS AND METHODOLOGY

An Air Quality Related Values (AQRV) analysis was conducted to assess the potential risk to AQRVs at the Everglades NP due to the proposed emissions from the Project. The Everglades NP is the closest Class I area to the Martin Plant site, and is located about 144 km south of the project site.

The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.
>
> Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register 1978).

The AQRVs include freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) are also evaluated.

The maximum predicted atmospheric concentrations due to the increase in emissions resulting from the proposed project are presented in Table 7-1. As shown, the predicted increase in impacts is very low for all pollutants considered.

7.3.2 IMPACTS TO SOILS

For soils, the potential and hypothesized effects of atmospheric deposition include:

- Increased soil acidification,
- Alteration in cation exchange,
- Loss of base cations, and
- Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

The soils of the Everglades NP are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as $CaCO_3$).

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the Everglades NP from the Project emissions precludes any significant impact on soils.

7.3.3 IMPACTS TO VEGETATION

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants, such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation, which is a very conservative approach.

The concentrations of the pollutants, duration of exposure and frequency of exposures influence the response of vegetation to atmospheric pollutants. 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 duration of the exposure.

Sulfur Dioxide

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When sulfur dioxide in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

Observed SO_2 effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-2 and 7-3, respectively. SO_2 gas at elevated levels has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of SO_2 range from 2.5 to 25 $\mu g/m^3$.

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour SO_2 concentrations of 790 to 1,570 $\mu g/m^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour SO_2 concentrations of 1,570 to 2,100 μg/m^3. Resistant species (injured at concentrations above 2,100 μg/m^3 for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 μg/m^3 SO_2 for 8 hours were not visibly damaged. This finding support the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour SO_2 concentrations of 920 μg/m^3.

Two lichen species indigenous to the park area exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 μg/m^3 for 6 hours/week for 10 weeks (Hart *et al.*, 1988).

Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 μg/m^3 for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 μg/m^3 SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979).

The maximum 3-, 8-, and 24-hour average SO_2 concentrations for the Project are predicted to be 0.80, 0.56, and 0.39 μg/m^3, respectively, at the Class I area. The maximum 3-hour average SO_2 concentrations predicted for the Project at the Class I areas are 0.4 percent or less of those that caused damage to the most sensitive lichens. The modeled annual incremental increase in SO_2 adds slightly to background levels of this gas and poses only a minimal threat to area vegetation.

<u>**Nitrogen Dioxide**</u>

Nitrogen dioxide (NO_2) is another emission of concern for the proposed plant expansion. This compound can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru *et al.*, 1979).

Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 $\mu g/m^3$ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

The maximum 1-, 3-, and 8-hour average NO_2 concentrations due to the Project are predicted to be 2.2, 2.0, and 1.4 $\mu g/m^3$, respectively, at the Class I area. These concentrations are approximately 0.015 to 0.06 percent of the levels that could potentially injure 5 percent of the plant foliage. For a chronic exposure, the maximum annual NO_2 concentration due to the Project is predicted to be 0.0017 $\mu g/m^3$ at the Class U area, which is 0.00005 to 0.0001 percent of the levels that caused minimal yield loss and chlorosis in plant tissue.

Although it has been shown that simultaneous exposure to SO_2 and NO_2 results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone and usually occurs at unnaturally high levels of each gas. Therefore, the concentrations within the park are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

Particulate Matter

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of PM that ranged from 210 to 366 $\mu g/m^3$ for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 $\mu g/m^3$ did not appear to be injurious to the tested plants.

The maximum 8-hour PM concentration due to the Project is predicted to be 0.23 $\mu g/m^3$ at the Class I area. This concentration is approximately 0.06 to 0.14 percent of the values that affected plant foliage. As a result, no significant effects to vegetative AQRVs are expected from the Project's emissions.

Carbon Monoxide

As with PM, information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of ATP, the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok *et al.* (1989) reported that exposure to $CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of 6.85×10^6 $\mu g/m^3$) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik *et al.* (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85×10^5 $\mu g/m^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

The maximum 1-hour average concentration due to the Project is 0.86 $\mu g/m^3$ in the Class I area which is less than 0.001 percent of the minimum value that caused inhibition in laboratory studies. The amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season. The maximum predicted annual concentration of 0.0086 $\mu g/m^3$ reflects more realistic, yet conservative, CO level for the Class I areas. This maximum concentration is predicted to be less than 0.00001 percent of the value that caused cytochrome *c* oxidase inhibition.

Sulfuric Acid Mist

Acidic precipitation or acid rain is coupled to SO_2 emissions mainly formed during the burning of fossil fuels. This pollutant is oxidized in the atmosphere and dissolves in rain forming sulfuric acid mist which falls as acidic precipitation (Ravera, 1989). Although concentration data are not available, sulfuric acid mist has been reported to yield necrotic spotting on the upper surfaces of leaves (Middleton *et al.*, 1950).

No significant adverse effects on vegetation are expected from the project's emissions because SO_2 concentrations, which lead directly to the formation of sulfuric acid mist concentrations, are predicted to be well below levels which have been documented as negatively affecting vegetation. During the last decade, much attention has been focused on acid rain. Acidic deposition is an ecosystem-level problem that affects vegetation because of some alterations of soil conditions such as increased leaching of essential base cations or elevated concentrations of aluminum in the soil water (Goldstein *et al.*, 1985). Although effects of acid rain in eastern North America have been well published and publicized, detrimental effects of acid rain on Florida vegetation are lacking documentation.

Summary

In summary, the phytotoxic effects on the Everglades NP from proposed project's emissions are expected to be minimal. It is important to note that the substances were evaluated with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.3.4 IMPACTS TO WILDLIFE

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary ambient air quality standards. Physiological and behavioral effects have been observed in experimental animals at or below these standards. No observable effects to fauna are expected at concentrations below the values reported in Table 7-4.

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the National Ambient Air Quality Standards. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

For impacts on wildlife, the lowest threshold values of SO_2, NO_x, and particulates that are reported to cause physiological changes are shown in Table 7-4. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area.

No significant effects on wildlife AQRVs from SO_2, NO_x, and particulates are expected. These results are considered indications of the risk of other air pollutant emissions predicted from the Project which is also considered to be negligible.

7.4 IMPACTS ON VISIBILITY

7.4.1 INTRODUCTION

The CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Sources of air pollution can cause visible plumes if emissions of PM_{10} and NO_x are sufficiently large. A plume will be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.

Visibility is an AQRV for the Everglades NP. Visibility can take the form of plume blight for nearby areas or regional haze for long distances (e.g., distances beyond 50 km). Because the Everglades NP is more than 50 km from the Project, the change in visibility is analyzed as regional haze.

Currently, there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and FLM of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report; and
- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report,* USFS, NPS, USFWS (December, 2000), referred to as the FLAG document.

The methods and assumptions recommended in these documents were used to assess visibility impairment due to the project.

7.4.2 ANALYSIS METHODOLOGY

Methodology

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient.

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the proposed Project. The criteria to determine if the Project's impacts are potentially significant are based on a change in extinction of 5 percent or greater for any day of the year.

Processing of visibility impairment for this study was performed with the CALPUFF model (see Appendix D) and the CALPUFF post-processing program CALPOST. The analysis was conducted in accordance with the most recent guidance from the FLAG report (December 2000). The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. Daily background extinction coefficients are calculated on a hour-by-hour basis using hourly relative humidity data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document. For the Class I area evaluated, the hygroscopic and non-hygroscopic components are 0.9 and 8.5 inverse mega meter (Mm^{-1}). CALPOST then predicts the percent extinction change for each day of the year.

Results

The results of the refined regional haze analysis are presented in Table 7-5. The results indicate that the proposed Project's maximum predicted impact on visibility at the Everglades NP is 2.75 percent for the combined-cycle operation on fuel oil. The maximum predicted impact on visibility when firing natural gas is 0.64 percent. The values are below the FLM's screening criteria of 5 percent change. Therefore, the Project is not expected to have an adverse impact on the existing regional haze in the Everglades NP.

7.4.3 SULFUR AND NITROGEN DEPOSITION

General Methods

As part of the AQRV analyses, total nitrogen (N) and sulfur (S) deposition rates were predicted at the Everglades NP Class I area. The deposition analysis thresholds (DAT) are based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen or sulfur. The CALPUFF model is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition;
- Nitric acid (species HNO_3), wet and dry deposition;
- NO_x, dry deposition; and
- Ammonium sulfate (species SO_4), wet and dry deposition.

For S deposition, the species include:

- SO2, wet and dry deposition; and
- SO4, wet and dry deposition.

The CALPUFF model produces results in units of $\mu g/m^2/s$. The modeled deposition rates are then converted to N or S deposition in kg/ha respectively, by using a multiplier equal to the ratio of the molecular weights of the substances (IWAQM Phase II report Section 3.3).

Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition of 0.01 kg/ha/yr were provided by the U.S. Fish and Wildlife Service (January 2002). A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant. The maximum N and S depositions predicted for the Project are, therefore, compared to these DAT or significant impact levels.

Results

The maximum predicted N and S depositions predicted for the Project in the PSD Class I area of the Everglades NP are summarized in Table 7-6. The maximum N and S deposition rates for the Project are predicted to be 0.0015 and 0.0004 kg/ha/yr, respectively. These maximum deposition rates are below the significant impact levels for N and S of 0.01 kg/ha/yr. As a result, the Project's emissions are not expected to have a significant adverse effect on N and S deposition at the Class I area.

Table 7-1 Maximum Pollutant Concentrations Predicted for the Project at the PSD Class I Area of the Everglades NP

Pollutant	Averaging Time	Maximum Concentrations ($\mu g/m^3$) [a]		
		Natural Gas	Fuel Oil	Natural Gas/ Fuel Oil
Combined-Cycle Operation [b]				
SO_2	Annual [c]	NM	NM	0.0013
	24-Hour	0.052	0.388	0.388
	8-Hour	0.082	0.556	0.556
	3-Hour	0.11	0.803	0.803
	1-Hour	0.139	0.902	0.902
PM_{10}	Annual [c]	NM	NM	0.0018
	24-Hour	0.086	0.174	0.174
	8-Hour	0.126	0.230	0.230
	3-Hour	0.170	0.334	0.334
	1-Hour	0.216	0.379	0.379
NO_2	Annual [c]	NM	NM	0.0017
	24-Hour	0.093	0.254	0.254
	8-Hour	0.186	0.458	0.458
	3-Hour	0.252	0.667	0.667
	1-Hour	0.302	0.726	0.726
CO	Annual [c]	NM	NM	0.0086
	24-Hour	0.346	0.309	0.346
	8-Hour	0.499	0.402	0.499
	3-Hour	0.677	0.586	0.677
	1-Hour	0.86	0.679	0.86
Simple-Cycle Operation [b]				
SO_2	Annual [c]	NM	NM	0.0013
	24-Hour	0.035	0.338	0.338
	8-Hour	0.051	0.499	0.499
	3-Hour	0.074	0.716	0.716
	1-Hour	0.081	0.787	0.787
PM_{10}	Annual [c]	NM	NM	0.0018
	24-Hour	0.039	0.069	0.069
	8-Hour	0.054	0.096	0.096
	3-Hour	0.074	0.133	0.133
	1-Hour	0.081	0.146	0.146
NO_2	Annual [c]	NM	NM	0.0017
	24-Hour	0.245	0.793	0.793
	8-Hour	0.452	1.439	1.439
	3-Hour	0.636	2.019	2.019
	1-Hour	0.398	2.234	2.234
CO	Annual [c]	NM	NM	0.0086
	24-Hour	0.185	0.259	0.259
	8-Hour	0.259	0.363	0.363
	3-Hour	0.363	0.509	0.509
	1-Hour	0.398	0.559	0.559

Note: NM = not modeled

[a] Concentrations are highest predicted using CALPUFF model and 1990 CALMET wind field for south Florida.

[b] Concentrations predicted for combined- and simple cycle operation are based on the operating scenario with the maximum hourly emissions. For both natural gas- and oil-firing, maximum emissions are based on the combustion turbines operating for baseload conditions at an ambient temperature of 35°F.

For combined cycle operation and natural gas-firing, duct burner emission are included. For simple cycle operation and natural gas-firing, combustion turbines are assumed to operate at higher power mode.

[c] Annual average concentrations are based on the operating scenarios with the maximum hourly emissions for the following annual hours.

1. For SO_2 and PM_{10}: combined cycle operation with natural gas- and fuel oil-firing for 8,260 and 500 hours, respectively;
2. For NO_2: combined cycle operation with natural gas-firing for 7,760, simple cycle operation with natural gas- and fuel oil-firing for 500 hours each; and
3. For CO: combined cycle operation with natural gas-firing for 8,760

Table 7-2. SO_2 Effects Levels for Various Plant Species

Plant Species	Observed Effect Level ($\mu g/m^3$)	Exposure (Time)	Reference
Sensitive to tolerant	920 (20 percent displayed visible injury)	3 hours	McLaughlin and Lee, 1974
Lichens	200-400	6 hr/wk for 10 weeks	Hart *et al.*, 1988
Cypress, slash pine, live oak, mangrove	1,300	8 hours	Woltz and Howe, 1981
Jack pine seedlings	470-520	24 hours	Malhotra and Kahn, 1978
Black oak	1,310	Continuously for 1 week	Carlson, 1979

Table 7-3. Sensitivity Groupings of Vegetation Based on Visible Injury at Different SO_2 Exposures[a]

Sensitivity Grouping	SO_2 Concentration		Plants
	1-Hour	3-Hour	
Sensitive	1,310 - 2,620 μG/m^3 (0.5 - 1.0 ppm)	790 - 1,570 μG/m^3 (0.3 - 0.6 ppm)	Ragweeds Legumes Blackberry Southern pines Red and black oaks White ash Sumacs
Intermediate	2,620 - 5,240 μG/m^3 (1.0 - 2.0 ppm)	1,570 - 2,100 μG/m^3 (0.6 - 0.8 ppm)	Maples Locust Sweetgum Cherry Elms Tuliptree Many crop and garden species
Resistant	>5,240 μG/m^3 (>2.0 ppm)	>2,100 μG/m^3 (>0.8 ppm)	White oaks Potato Upland cotton Corn Dogwood Peach

[a] Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

Source: EPA, 1982a.

Table 7-4. Examples of Reported Effects of Air Pollutants at Concentrations Below National Secondary Ambient Air Quality Standards

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Sulfur Dioxide[a]	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 day/week for 10 weeks
	Decreased abundance in deer mice	13 to 157	continually for 5 months
Nitrogen Dioxide[b,c]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[a]	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	2 hours

Source: a Newman and Schreiber, 1988.
b Gardner and Graham, 1976.
c Trzeciak et al., 1977.

Table 7-5. Maximum 24-hour Average Visibility Impairment Predicted for the Project at the PSD Class I Area of the Everglades NP

Operating Mode	Maximum Visibility Impairment (%) [a]		Visibility Impairment Criteria (%)
	Natural Gas	Fuel Oil	
Combined-Cycle	0.64	2.75	5.0
Simple-Cycle	0.41	1.91	5.0

[a] Concentrations are highest predicted using CALPUFF model and 1990 CALMET wind field for south Florida. Background extinctions calculated using FLAG Document (December 2000) values and hourly relative humidity data.

[b] Concentrations predicted for combined- and simple cycle operation are based on the operating scenario with the maximum hourly emissions. For both natural gas- and oil-firing, maximum emissions are based on the combustion turbines operating for baseload conditions at an ambient temperature of 35°F.

For combined cycle operation and natural gas-firing, duct burner emission are included. For simple cycle operation and natural gas-firing, combustion turbines are assumed to operate at higher power mode.

Table 7-6. Maximum Sulfur and Nitrogen Annual Deposition Predicted for the Project at the PSD Class I Area of the Everglades NP

Species	Maximum Deposition (μg/m2/s)			Species Molecular Weight (MW)	Conversion of Species to Nitrogen (N) or Sulfur (S)					Deposition (kg/ha/yr) [a]		Deposition Analysis Threshold [b] (kg/ha/yr)
	Dry	Wet	Total		Basis	Deposition Molecule	No. of Deposition Molecules	Deposition Molecule MW	Ratio MW Dep. Molecule to Species	N	S	
Nitrogen (N) Deposition												
Nitrate (NO_3)	1.809E-08	6.792E-07	6.973E-07	62	Ammonium nitrate (NH_4NO_3)	N	2	28	0.452	0.00010		
Nitric acid (HNO_3)	4.189E-06	8.249E-06	1 244E-05	63	HNO_3	N	1	14	0.222	0.00087		
Nitrogen oxides (NOx as NO_2)	2.771E-06	NA	2 771E-06	46	NO_2	N	1	14	0.304	0.00027		
Sulfate (SO_4)	3.889E-08	2.928E-06	2.967E-06	96	Ammonium sulfate ($(NH_4)_2SO_4$)	N	2	28	0.292	0.00027		
TOTAL										0.0015		0.01
Sulfur (S) Deposition												
Sulfur dioxide (SO_2)	3.897E-06	4.328E-06	8.532E-07	64	SO_2	S	1	32	0.500		0.00013	
Sulfate (SO_4)	3.889E-08	2 928E-06	2.967E-06	96	Ammonium sulfate ($(NH_4)_2SO_4$)	S	1	32	0.333		0.00031	
TOTAL											0.0004	0.01

[a] Deposition is calculated by multiplying maximum predicted total deposition ($\mu g/m^2/s$) for total species by ratio of molecular weights of deposition molecule to species by conversion factor. Conversion factor is used to convert $\mu g/m^2/s$ to kg/hectare (ha)/yr using following units:

$\mu g/m^2/s$	x	0.000001	g/μg
	x	0.001	kg/g
	x	10000	m^2/hectare
	x	3600	sec/hr
	x	8760	hr/yr =kg/ha/yr
	or		
$\mu g/m^2/s$	x	315.36	= kg/ha/yr

[b] Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition provided by the U.S. Fish and Wildlife Service, January 2002.
A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant.

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APPENDIX A

EXPECTED PERFORMANCE AND EMISSION INFORMATION ON "F" CLASS COMBUSTION TURBINE

(Note: SO_2 based on 0.2 gr/100 cf of H_2S. Actual total sulfur based on 1 gr/100 cf to account for odorant (mercaptans) in pipeline gas.)

Table A-1. Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only Turbine Inlet Temperature 35 °F Case 8	 59 °F Case 6	 75 °F Case 4	 80 °F Power Aug	 95 °F Case 2	CT with Duct Burner Turbine Inlet Temperature 35 °F w/DB Case 7	 59 °F w/DB Case 5	 75 °F w/DB Case 3	 80 °F w/DB Power Aug	 95 °F w/DB Case 1
Combustion Turbine Performance										
Net power output (MW)	181.64	172.44	163.14	164.44	149.74	181 64	172.44	163.14	164.44	149 74
Net heat rate (Btu/kWh, LHV)	9,213	9,280	9,412	9440	9,666	9,213	9,280	9,412	9440	9,666
(Btu/kWh, HHV)	10,227	10,301	10,447	10,481	10,729	10,227	10,301	10,447	10,481	10,729
Heat Input (MMBtu/hr, LHV)	1,674	1,600	1,536	1552 7	1,447	1,674	1,600	1,536	1552 7	1,447
(MMBtu/hr, HHV)	1,858	1,776	1,704	1,723	1,607	1,858	1,776	1,704	1,723	1,607
Inlet Fogger	Off	Off	Off	On	Off	Off	Off	Off	On	Off
Relative Humidity (%)	20	60	60		50	20	60	60		50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127	23,127	23,127	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1 110
Duct Burner (DB)										
Heat input (MMBtu/hr, HHV)	0	0	0	0	0	550	550	550	550	550
(MMBtu/hr, LHV)	0	0	0	0	0	495.5	495.5	495 5	495.5	495.5
CT/DB Exhaust Flow										
Mass Flow (lb/hr)- with no margin	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000	3,728,099 6	3,561,100	3,440,100	3,466,100	3,279,100
- provided	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000					
Temperature (°F)	1,095	1,116	1,128	1,125	1,143	1,095	1,116	1,128	1,125	1,143
Moisture (% Vol.)	7.56	8 39	9.04	9 7	9.92	9 59	10.50	11.21	12.49	12.17
Oxygen (% Vol.)	12.60	12.44	12 36	12 19	12.27	10.35	10.10	9 94	10.34	9.75
Molecular Weight	28.49	28.39	28 33	28.25	28 22	28 36	28.26	28.18	29.68	28.08
Fuel Usage										
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))										
Heat input (MMBtu/hr, LHV)	1,674	1,600	1,536	1,553	1,447	1,674	1,600	1,536	1,553	1,447
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	80,322	76,808	73,698	74,524	69,470	80,322	76,808	73,698	74,524	69,470
Heat content (Btu/cf, LHV)- assumed	933	933	933	933	933	933	933	933	933	933
Fuel density (lb/ft^3)	0 0448	0.0448	0.0448	0.0448	0 0448	0.0448	0.0448	0 0448	0 0448	0.0448
Fuel usage (cf/hr)- calculated	1,792,892	1,714,470	1,645,047	1,663,474	1,550,662	1,792,892	1,714,470	1,645,047	1,663,474	1,550,662
Fuel Usage - Duct Burner Only										
Fuel usage (lb/hr)- calculated	0	0	0	0	0	23,782	23,782	23,782	23,782	23,782
Fuel usage (cf/hr)- calculated	0	0	0	0	0	530,846	530,846	530,846	530,846	530,846
CT/Bypass and HRSG Stack										
CT/Bypass-Stack height (ft)	80	80	80	80	80	80	80	80	80	80
Diameter (ft)	22	22	22	22	22	22	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120	120	120	120	120	120	120
Diameter (ft)	19	19	19	19	19	19	19	19	19	19
CT/Bypass Stack Flow Conditions										
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116 8] / 60 min/hr										
Mass flow (lb/hr)	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000	NA	NA	NA	NA	NA
Temperature (°F)	1,095	1,116	1,128	1,125	1,143	NA	NA	NA	NA	NA
Molecular weight	28.49	28.39	28.33	28.25	28.22	NA	NA	NA	NA	NA
Volume flow (acfm)- calculated	2,460,544	2,389,462	2,331,000	2,350,164	2,250,314	NA	NA	NA	NA	NA
(ft^3/s)- calculated	41,009	39,824	38,850	39,169	37,505	NA	NA	NA	NA	NA
Diameter (ft)	22	22	22	22	22	NA	NA	NA	NA	NA
Velocity (ft/sec)- calculated	107.9	104.8	102 2	103.0	98 7	NA	NA	NA	NA	NA
HRSG Stack Flow Conditions										
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min										
Mass flow (lb/hr)	3,706,000	3,539,000	3,418,000	3,444,000	3,257,000	3,728,100	3,561,100	3,440,100	3,466,100	3,279,100
HRSG Stack Temperature (°F)	203	202	204	204	201	189	188	189	188	190
Molecular weight	28.49	28 39	28.33	28.25	28 22	28.36	28.26	28 18	29.68	28.08
Volume flow (acfm)	1,048,619	1,004,150	974,675	984,548	927,921	1,037,294	993,802	964,236	920,636	923,335
Diameter (ft)	19	19	19	19	19	19	19	19	19	19
Velocity (ft/sec)- calculated	61.6	59 0	57.3	57.9	54 5	61.0	58.4	56 7	54.1	54.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2, 14.7 lb/ft^2

Source: GE, 2000 - CT Performance Data, Golder Associates, 2001 - DB Calculations

Table A-2. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only Turbine Inlet Temperature					CT with Duct Burner Turbine Inlet Temperature				
	35 °F Case 8	59 °F Case 6	75 °F Case 4	80 °F Power Aug	95 °F Case 2	35 °F w/DB Case 7	59 °F w/DB Case 5	75 °F w/DB Case 3	80 °F w/DB Power Aug.	95 °F w/DB Case 1
Particulate from CT, DB, and SCR										
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only										
a. PM_{10} (front half) (lb/hr)										
CT- provided	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
DB (lb/hr) - calculated	0.0	0.0	0.0	0.0	0.0	5.5	5.5	5.5	5.5	5.5
Total CT/DB emission rate (lb/hr)	9.0	9.0	9.0	9.0	9.0	14.5	14.5	14.5	14.5	14.5
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})										
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3										
SO_2 emission rate (lb/hr)- calculated	10.2	9.8	9.4	9.5	8.9	13.3	12.8	12.4	12.5	11.9
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100	100	100	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	2.07	1.98	1.90	1.92	1.79	2.68	2.59	2.51	2.53	2.40
Total CT/Bypass stack emission rate (lb/hr) [a]	9.0	9.0	9.0	9.0	9.0	NA	NA	NA	NA	NA
Total HRSG stack emission rate (lb/hr) [a + b]	11.1	11.0	10.9	10.9	10.8	17.2	17.1	17.0	17.0	16.9
(lb/mmBtu, HHV)	0.0060	0.0062	0.0064	0.0063	0.0067	0.0071	0.0073	0.0075	0.0075	0.0078
Sulfur Dioxide										
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100										
Fuel use (cf/hr)	1,792,892	1,714,470	1,645,047	1,663,474	1,550,662	2,323,738	2,245,316	2,175,893	2,194,320	2,081,507
Sulfur content (grains/ 100 cf)	2	2	2	2	2	2	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2	2	2	2	2	2	2
CT/Bypass stack emission rate (lb/hr)	10.2	9.8	9.4	9.5	8.9	NA	NA	NA	NA	NA
HRSG stack emission rate (lb/hr)	10.2	9.8	9.4	9.5	8.9	13.3	12.8	12.4	12.5	11.9
Nitrogen Oxides										
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft² x Volume flow (acfm) x 46 (mole wgt NOx) x 60 min/hr / [1545 x (CT temp (°F) + 460) x (20.9-15) x 1,000,000 (adj for ppm)]										
CT/DB, ppmvd @15% O_2	9	9	9	12	9	12.0	12.0	12.1	14.9	12.1
Moisture (%)	7.56	8.39	9.04	9.7	9.92	9.59	10.50	11.21	12.49	12.17
Oxygen (%)	12.6	12.44	12.36	12.19	12.27	10.35	10.10	9.94	10.34	9.75
Turbine Flow (acfm)	2,460,544	2,389,462	2,331,000	2,350,164	2,250,314	2,486,882	2,415,907	2,357,879	2,403,989	2,277,437
Turbine Exhaust Temperature (°F)	1,095	1,116	1,128	1,125	1,143	1,095	1,116	1,128	1,125	1,143
CT/DB Emission rate (lb/hr)	61.3	58.7	56.3	76.2	53.1	116.3	113.7	111.3	131.2	108.1
CT/Bypass Stack, ppmvd @ 15% O_2	9	9	9	12	9	NA	NA	NA	NA	NA
CT/Bypass Stack Emission rate (lb/hr)	61.3	58.7	56.3	76.2	53.1	NA	NA	NA	NA	NA
HRSG Stack, ppmvd @ 15% O_2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
HRSG Stack Emission rate (lb/hr)	17.0	16.3	15.6	15.9	14.7	24.2	23.6	23.1	22.1	22.3
Carbon Monoxide										
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft² x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj. for ppm)]										
Basis, ppmvd	9	9	9	15	9	22.1	22.9	23.6	29.5	24.5
Basis, ppmvd @ 15% O2 - calculated	7.3	7.3	7.3	12.0	7.3	13.8	14.1	14.3	19.2	14.7
Moisture (%)	7.56	8.39	9.04	9.70	9.92	9.59	10.50	11.21	12.49	12.17
Oxygen (%)	12.60	12.44	12.36	12.19	12.27	10.35	10.10	9.94	10.34	9.75
Turbine Flow (acfm)	2,460,544	2,389,462	2,331,000	2,350,164	2,250,314	2,486,882	2,415,907	2,357,879	2,403,989	2,277,437
Turbine Exhaust Temperature (°F)	1,095	1,116	1,128	1,125	1,143	1,095	1,116	1,128	1,125	1,143
CT/DB Emission rate (lb/hr)	28.6	27.5	26.6	45.0	25.5	72.6	71.5	70.6	89.0	69.5
CT/Bypass Stack Emission rate (lb/hr)	28.6	27.5	26.6	45.0	25.5	NA	NA	NA	NA	NA
HRSG Stack Emission rate (lb/hr)	28.6	27.5	26.6	45.0	25.5	72.6	71.5	70.6	89.0	69.5

Table A-2 Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	CT Only Turbine Inlet Temperature					CT with Duct Burner Turbine Inlet Temperature				
	35 °F Case 8	59 °F Case 6	75 °F Case 4	80 °F Power Aug	95 °F Case 2	35 °F w/DB Case 7	59 °F w/DB Case 5	75 °F w/DB Case 3	80 °F w/DB Power Aug	95 °F w/DB Case 1
Volatile Organic Compounds										
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116 8 lb/ft^2 x Volume flow (acfm) x 16 (mole wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj for ppm)]										
Basis, ppmvw	1.5	1.5	1.5	1.5	1.5	6 2	6 5	6 7	6 6	7.0
Basis, ppmvd @ 15% O2 - calculated	1.3	1.3	1.3	1.3	1.3	4 3	4 4	4 6	4.9	4 8
Moisture (%)	7.56	8 39	9 04	9.70	9 92	9 59	10.50	11.21	12.49	12.17
Oxygen (%)	12 60	12.44	12.36	12.19	12 27	10.35	10.10	9.94	10.34	9 75
Turbine Flow (acfm)	2,460,544	2,389,462	2,331,000	2,350,164	2,250,314	2,486,882	2,415,907	2,357,879	2,403,989	2,277,437
Turbine Exhaust Temperature (°F)	1,095	1,116	1,128	1,125	1,143	1,095	1,116	1,128	1,125	1,143
CT/DB Emission rate (lb/hr)	2 89	2 74	2 63	2.64	2 49	11.69	11.54	11.43	11 44	11.29
CT/Bypass Stack Emission rate (lb/hr)	2 89	2.74	2 63	2.64	2 49	NA	NA	NA	NA	NA
HRSG Stack Emission rate (lb/hr)	2 89	2.74	2 63	2.64	2 49	11 69	11.54	11 43	11.44	11 29
Sulfuric Acid Mist										
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100										
CT SO_2 emission rate (lb/hr) - provided	10 2	9.8	9 4	9.5	8 9	10.2	9 8	9 4	9.5	8.9
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10	10	10	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0	0	3 0	3 0	3 0	3 0	3 0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20	20	20	20	20	20	20
CT/Bypass Stack Emission rate (lb/hr)	1.02	0.98	0.94	0.95	0.89	NA	NA	NA	NA	NA
HRSG Stack Emission rate (lb/hr)	1.02	0.98	0 94	0 95	0 89	1.63	1.59	1.55	1.56	1.49
Lead										
Lead (lb/hr) = NA										
Emission Rate Basis	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Note ppmvd= parts per million, volume dry; O_2= oxygen.

Source GE, 2000 - CT Performance Data, Golder Associates, 2001 - DB Calculations

Table A-3. Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F	59 °F	75 °F	95 °F
	Case 12	Case 11	Case 10	Case 9
Combustion Turbine Performance				
Net power output (MW)	136 7	129.24	122.24	112.24
Net heat rate (Btu/kWh, LHV)	9,855	10,043	10,236	10,602
(Btu/kWh, HHV)	10,939	11,148	11,362	11,769
Heat Input (MMBtu/hr, LHV)	1,347	1,298	1,251	1,190
(MMBtu/hr, HHV)	1,495	1,441	1,389	1,321
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1 110	1 110
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	2,979,000	2,888,000	2,803,000	2,694,000
- provided	2,979,000	2,888,000	2,803,000	2,694,000
Temperature (°F)	1,122	1,139	1,153	1,170
Moisture (% Vol.)	7 49	8 27	8.92	9 8
Oxygen (% Vol)	12 67	12 57	12.49	12 41
Molecular Weight	28 50	28 41	28 33	28.23
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,347	1,298	1,251	1,190
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	64,660	62,299	60,058	57,115
Heat content (Btu/cf, LHV)- assumed	933	933	933	933
Fuel density (lb/ft^3)	0.0448	0.0448	0 0448	0.0448
Fuel usage (cf/hr)- calculated	1,443,832	1,391,103	1,341,054	1,275,357
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
CT/Bypass Stack Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp (°F)+ 460°F)] / [Molecular weight x 2116 8] / 60 min/hr				
Mass flow (lb/hr)	2,979,000	2,888,000	2,803,000	2,694,000
Temperature (°F)	1,122	1,139	1,153	1,170
Molecular weight	28 50	28.41	28.33	28.23
Volume flow (acfm)- calculated	2,011,853	1,977,488	1,941,432	1,892,412
(ft^3/s)- calculated	33,531	32,958	32,357	31,540
Diameter (ft)	22 0	22 0	22.0	22.0
Velocity (ft/sec)- calculated	88.2	86.7	85 1	83.0
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3 14159] / 60 sec/min				
Mass flow (lb/hr)	2,979,000	2,888,000	2,803,000	2,694,000
HRSG Stack Temperature (°F)	187	188	189	190
Molecular weight	28 50	28.41	28 33	28.23
CT volume flow (acfm)	822,545	801,136	781,026	754,411
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	48 4	47 1	45.9	44 3

Note. Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116 8 lb(force)/ft^2, 14 7 lb/ft^3

Source: GE, 2000 - CT Performance Data.

Table A-4 Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 12	59 °F Case 11	75 °F Case 10	95 °F Case 9
Particulate from CTand SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a PM_{10} (front half) (lb/hr)				
CT- provided	9 0	9 0	9 0	9.0
b PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	8.3	7.9	7.7	7.3
Conversion (%) from SO_2 to SO_3	9 8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	1 67	1.61	1.55	1.47
Total CT/Bypass stack emission rate (lb/hr) [a]	9 0	9 0	9 0	9 0
Total HRSG stack emission rate (lb/hr) [a + b]	10 7	10 6	10 5	10 5
(lb/mmBtu, HHV)	0 0068	0.0070	0.0072	0 0075
Sulfur Dioxide				
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel use (cf/hr)	1,443,832	1,391,103	1,341,054	1,275,357
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	8 3	7.9	7.7	7 3
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT / DB, ppmvd @15% O_2	9	9	9	9
Moisture (%)	7 49	8.27	8.92	9 8
Oxygen (%)	12 67	12.57	12.49	12 41
Turbine Flow (acfm)	2,011,853	1,977,488	1,941,432	1,892,412
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
CT/DB Emission rate (lb/hr)	48.9	47.1	45.4	43.1
CT/Bypasss Stack, ppmvd @ 15% O_2	9	9	9	9
CT/Bypass Stack Emission rate (lb/hr)	48.89	47.09	45 45	43.14
HRSG Stack, ppmvd @ 15% O_2	2.5	2 5	2 5	2 5
HRSG Stack Emission rate (lb/hr)	13.6	13.1	12.6	12.0
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116 8 lb/ft^2 x Volume flow (acfm) x 28 (mole wgt CO) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	9	9	9	9
Moisture (%)	7 49	8.27	8.92	9.8
Turbine Flow (acfm)	2,011,853	1,977,488	1,941,432	1,892,412
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
HRSG Exhaust Temperature (°F)	187	188	189	190
Bypass/HRSG stack emission rate (lb/hr)- provided	24 4	23 5	22 7	21.7

Table A-4. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F	59 °F	75 °F	95 °F
	Case 12	Case 11	Case 10	Case 9
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	1.5	1.5	1.5	1.5
Moisture (%)	7.49	8.27	8.92	9.8
Turbine Flow (acfm)	2,011,853	1,977,488	1,941,432	1,892,412
Turbine Exhaust Temperature (°F)	1,122	1,139	1,153	1,170
HRSG Exhaust Temperature (°F)	186.8	186.8	186.8	186.8
Bypass/HRSG stack emission rate (lb/hr)- provided	2.32	2.24	2.16	2.07
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	8.3	7.9	7.7	7.3
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	0.83	0.79	0.77	0.73
Lead				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry, O_2= oxygen.

Source: GE, 2000 - CT Performance Data

Table A-5 Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 16	59 °F Case 15	75 °F Case 14	95 °F Case 13
Combustion Turbine Performance				
Net power output (MW)	91.1	86.5	81.34	74.64
Net heat rate (Btu/kWh, LHV)	11,820	12,050	12,415	12,866
(Btu/kWh, HHV)	13,120	13,375	13,780	14,281
Heat Input (MMBtu/hr, LHV)	1,077	1,042	1,010	960
(MMBtu/hr, HHV)	1,195	1,157	1,121	1,066
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	2,456,000	2,396,000	2,336,000	2,267,000
- provided	2,456,000	2,396,000	2,336,000	2,267,000
Temperature (°F)	1,168	1,184	1,195	1,200
Moisture (% Vol.)	7.21	7.97	8.62	9.45
Oxygen (% Vol.)	12.99	12.90	12.83	12.80
Molecular Weight	28.51	28.43	28.35	28.25
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,077	1,042	1,010	960
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	51,682	50,026	48,467	46,091
Heat content (Btu/cf, LHV)- assumed	933	933	933	933
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,154,037	1,117,062	1,082,231	1,029,181
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
CT/Bypass Stack Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	2,456,000	2,396,000	2,336,000	2,267,000
Temperature (°F)	1,168	1,184	1,195	1,200
Molecular weight	28.51	28.43	28.35	28.25
Volume flow (acfm)- calculated	1,705,874	1,685,637	1,658,984	1,620,525
(ft^3/s)- calculated	28,431	28,094	27,650	27,009
Diameter (ft)	22.0	22.0	22.0	22.0
Velocity (ft/sec)- calculated	74.8	73.9	72.7	71.1
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	2,456,000	2,396,000	2,336,000	2,267,000
HRSG Stack Temperature (°F)	175	178	175	182
Molecular weight	28.51	28.43	28.35	28.25
CT volume flow (acfm)	665,689	653,646	636,829	626,928
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	39.1	38.4	37.4	36.9

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3

Source: GE, 2000 - CT Performance Data

Table A-6 Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 16	59 °F Case 15	75 °F Case 14	95 °F Case 13
Particulate from CTand SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a PM_{10} (front half) (lb/hr)				
CT- provided	9 0	9 0	9 0	9.0
b PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	6 6	6 4	6.2	5.9
Conversion (%) from SO_2 to SO_3	9.8	9.8	9 8	9 8
MW SO_3/ SO_2 (80/64)	1 3	1 3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1 7	1 7	1 7	1 7
SCR Particulate (lb/hr)- calculated	1 33	1 29	1.25	1.19
Total CT/Bypass stack emission rate (lb/hr) [a]	9 0	9 0	9.0	9 0
Total HRSG stack emission rate (lb/hr) [a + b]	10 3	10 3	10.2	10 2
(lb/mmBtu, HHV)	0 0081	0 0083	0 0085	0 0089
Sulfur Dioxide				
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel use (cf/hr)	1,154,037	1,117,062	1,082,231	1,029,181
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	6.6	6 4	6.2	5.9
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20 9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116 8 lb/ft^2 x Volume flow (acfm) x 46 (mole wgt NOx) x 60 min/hr / [1545 x (CT temp (°F) + 460) x (20 9-15) x 1,000,000 (adj. for ppm)]				
CT / DB, ppmvd @15% O_2	9	9	9	9
Moisture (%)	7 21	7 97	8.62	9 45
Oxygen (%)	12 99	12 90	12.83	12.80
Turbine Flow (acfm)	1,705,874	1,685,637	1,658,984	1,620,525
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
CT/DB Emission rate (lb/hr)	38 7	37.5	36.2	34.5
CT/Bypasss Stack, ppmvd @ 15% O_2	9	9	9	9
CT/Bypass Stack Emission rate (lb/hr)	38 70	37 46	36 25	34.49
HRSG Stack, ppmvd @ 15% O_2	2 5	2 5	2 5	2.5
HRSG Stack Emission rate (lb/hr)	10 8	10 4	10 1	9 6
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole wgt CO) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj for ppm)]				
Basis, ppmvd	9	9	9	9
Moisture (%)	7.21	7.97	8 62	9 45
Turbine Flow (acfm)	1,705,874	1,685,637	1,658,984	1,620,525
Turbine Exhaust Temperature (°F)	1,168	1,184	1,195	1,200
HRSG Exhaust Temperature (°F)	175	178	175	182
Bypass/HRSG stack emission rate (lb/hr)- provided	20 1	19 5	19.0	18 3

Table A-6 Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 16	59 °F Case 15	75 °F Case 14	95 °F Case 13
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116 8 lb/ft^2 x Volume flow (acfm) x 16 (mole wgt as methane) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj for ppm)]				
Basis, ppmvw	1 5	1.5	1.5	1.5
Moisture (%)	7.21	7 97	8 62	9.45
Turbine Flow (acfm)	1,705,874	1,685,637	1,658,984	1,620,525
Turbine Exhaust Temperature (°F)	1,168	1,184	-1,195	1,200
HRSG Exhaust Temperature (°F)	175	175	175	175
Bypass/HRSG stack emission rate (lb/hr)- provided	1.92	1.86	1 81	1.74
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	6 6	6 4	6 2	5 9
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	0 66	0.64	0.62	0.59
Lead				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA

Note. ppmvd= parts per million, volume dry, O_2= oxygen.

Source GE, 2000 - CT Performance Data

Table A-7. Design Information and Stack Parameters for the FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Higher Power Modes

Parameter	Turbine Inlet Temperature 35 °F Case 20	59 °F Case 19	75 °F Case 18	95 °F Case 17
Combustion Turbine Performance				
Net power output (MW)	190 3	182 44	174 64	165 54
Net heat rate (Btu/kWh, LHV)	9,080	9,210	9,330	9,482
(Btu/kWh, HHV)	10,079	10,223	10,356	10,525
Heat Input (MMBtu/hr, LHV)	1,728	1,680	1,629	1,570
(MMBtu/hr, HHV)	1,918	1,865	1,809	1,742
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	20,835	20,835	20,835	20,835
(Btu/lb, HHV)	23,127	23,127	23,127	23,127
(HHV/LHV)	1 110	1.110	1 110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	3,713,000	3,558,000	3,478,000	3,356,000
- provided	3,713,000	3,558,000	3,478,000	3,356,000
Temperature (°F)	1,109	1,130	1,145	1,158
Moisture (% Vol.)	7 74	8 84	9 61	10 73
Oxygen (% Vol.)	12.39	12 15	12 01	11.81
Molecular Weight	28.48	28.36	28.27	28.15
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,728	1,680	1,629	1,570
Heat content (Btu/lb, LHV)	20,835	20,835	20,835	20,835
Fuel usage (lb/hr)- calculated	82,933	80,648	78,205	75,335
Heat content (Btu/cf, LHV)- assumed	933	933	933	933
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,851,839	1,800,825	1,746,274	1,682,185
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
CT/Bypass Stack Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,713,000	3,558,000	3,478,000	3,356,000
Temperature (°F)	1,109	1,130	1,145	1,158
Molecular weight	28.48	28 36	28.27	28 15
Volume flow (acfm)- calculated	2,488,641	2,426,858	2,402,002	2,346,741
(ft^3/s)- calculated	41,477	40,448	40,033	39,112
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	109.1	106 4	105 3	102.9
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	3,713,000	3,558,000	3,478,000	3,356,000
HRSG Stack Temperature (°F)	205	205	207	204
Molecular weight	28.48	28.36	28.27	28.15
CT volume flow (acfm)	1,055,240	1,014,759	998,327	962,538
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	62.0	59.7	58.7	56 6

Note. Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116 8 lb(force)/ft²; 14 7 lb/ft^3

Source: GE, 2000.

Table A-8 Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Higher Power Modes

Parameter	Turbine Inlet Temperature			
	35 °F Case 20	59 °F Case 19	75 °F Case 18	95 °F Case 17
Particulate from CTand SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a PM_{10} (front half) (lb/hr)				
CT- provided	9.0	9.0	9.0	9.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversio				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	10.6	10.3	10.0	9.6
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	2.14	2.08	2.02	1.94
Total CT/Bypass stack emission rate (lb/hr) [a]	9.0	9.0	9.0	9.0
Total HRSG stack emission rate (lb/hr) [a + b]	11.1	11.1	11.0	10.9
(lb/mmBtu, HHV)	0.0056	0.0057	0.0058	0.0060
Sulfur Dioxide				
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel use (cf/hr)	1,851,839	1,800,825	1,746,274	1,682,185
Sulfur content (grains/ 100 cf)	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	10.6	10.3	10.0	9.6
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp (°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @15% O_2	15	15	15	15
Moisture (%)	7.74	8.84	9.61	10.73
Oxygen (%)	12.39	12.15	12.01	11.81
Turbine Flow (acfm)	2,488,641	2,426,858	2,402,002	2,346,741
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
CT/DB Emission rate (lb/hr)	105.1	101.3	99.0	95.5
CT/Bypasss Stack, ppmvd @ 15% O_2	15	15	15	15
CT/Bypass Stack Emission rate (lb/hr)	105.1	101.3	99.0	95.5
HRSG Stack, ppmvd @ 15% O_2	2.5	2.5	2.5	2.5
HRSG Stack Emission rate (lb/hr)	17.5	16.9	16.5	15.9
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole wgt CO) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	15	15	15	15
Moisture (%)	7.74	8.84	9.61	10.73
Turbine Flow (acfm)	2,488,641	2,426,858	2,402,002	2,346,741
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
HRSG Exhaust Temperature (°F)	205	205	207	204
Bypass/HRSG stack emission rate (lb/hr)- provided	50.5	48.0	46.7	44.7

Table A-8. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Higher Power Modes

Parameter	Turbine Inlet Temperature			
	35 °F Case 20	59 °F Case 19	75 °F Case 18	95 °F Case 17
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116 8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	1.5	1 5	1 5	1.5
Moisture (%)	7.74	8.84	9.61	10 73
Turbine Flow (acfm)	2,488,641	2,426,858	2,402,002	2,346,741
Turbine Exhaust Temperature (°F)	1,109	1,130	1,145	1,158
HRSG Exhaust Temperature (°F)	205	205	207	204
Bypass/HRSG stack emission rate (lb/hr)- provided	2 89	2.75	2.67	2.55
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	10 6	10 3	10 0	9 6
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	1.06	1.03	1.00	0.96
Lead				
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA

Note: ppmvd= parts per million, volume dry, O_2= oxygen

Source: GE, 2000 - CT Performance Data

Table A-9. Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature			
	35 °F	59 °F	75 °F	95 °F
	Case 28	Case 26	Case 24	Case 22
Combustion Turbine Performance				
Net power output (MW)	189.1	180 4	172.5	172.5
Net heat rate (Btu/kWh, LHV)	10,019	10,037	10,101	9,486
(Btu/kWh, HHV)	10,620	10,639	10,707	10,056
Heat Input (MMBtu/hr, LHV)	1,895	1,811	1,743	1,637
(MMBtu/hr, HHV)	2,008	1,919	1,847	1,735
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	18,367	18,367	18,367	18,367
(Btu/lb, HHV)	19,469	19,469	19,469	19,469
(HHV/LHV)	1.060	1 060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	3,862,000	3,683,000	3,552,000	3,376,000
- provided	3,862,000	3,683,000	3,552,000	3,376,000
Temperature (°F)	1,074	1,098	1,113	1,131
Moisture (% Vol.)	10 6	11 21	11.68	12.18
Oxygen (% Vol.)	11.19	11 06	11.00	11 00
Molecular Weight	28 39	28 33	28.27	28 21
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,895	1,811	1,743	1,637
Heat content (Btu/lb, LHV)	18,367	18,367	18,367	18,367
Fuel usage (lb/hr)- calculated	103,147	98,584	94,871	89,100
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
CT/Bypass Stack Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp (°F)+ 460°F)] / [Molecular weight x 2116 8] / 60 min/hr				
Mass flow (lb/hr)	3,862,000	3,683,000	3,552,000	3,376,000
Temperature (°F)	1,074	1,098	1,113	1,131
Molecular weight	28.39	28.33	28.27	28.21
Volume flow (acfm)- calculated	2,538,306	2,464,273	2,403,828	2,316,007
(ft^3/s)- calculated	42,305	41,071	40,064	38,600
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	111.3	108.0	105 4	101.5
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	3,862,000	3,683,000	3,552,000	3,376,000
HRSG Stack Temperature (°F)	297	295	294	294
Molecular weight	28.39	28.33	28.27	28.21
CT volume flow (acfm)	1,252,275	1,193,859	1,151,484	1,096,864
(ft^3/s)- calculated	20,871	19,898	19,191	18,281
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	73.6	70 2	67.7	64 5

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14 7 lb/ft²

Source. GE, 2000 - CT Performance Data.

Table A-10. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 28	59 °F Case 26	75 °F Case 24	95 °F Case 22
Particulate from CTand SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a PM_{10} (front half) (lb/hr)				
CT- provided	17.0	17 0	17.0	17.0
b PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	103 1	98.6	94 9	89 1
Conversion (%) from SO_2 to SO_3	9.8	9.8	9 8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	20 85	19.93	19.18	18 01
Total CT/Bypass stack emission rate (lb/hr) [a]	17.0	17.0	17.0	17 0
Total HRSG stack emission rate (lb/hr) [a + b]	37.8	36 9	36 2	35 0
(lb/mmBtu, HHV)	0 0188	0 0192	0 0196	0 0202
Sulfur Dioxide				
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100				
Fuel oil Sulfur Content	0 05%	0 05%	0 05%	0 05%
Fuel oil use (lb/hr)	103,147	98,584	94,871	89,100
lb SO2 / lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	103.1	98 6	94 9	89 1
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20 9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116 8 lb/ft^2 x Volume flow (acfm) x 46 (mole wgt NOx) x 60 min/hr / [1545 x (CT temp (°F) + 460) x (20 9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @15% O_2	42	42	42	42
Moisture (%)	10 6	11 21	11 68	12 18
Oxygen (%)	11.19	11.06	11.00	11.00
Turbine Flow (acfm)	2,538,306	2,464,273	2,403,828	2,316,007
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
CT/DB Emission rate (lb/hr)	333 8	319.2	306 8	288 2
CT/Bypasss Stack, ppmvd @ 15% O_2	42	42	42	42
CT/Bypass Stack Emission rate (lb/hr)	333 8	319 2	306 8	288.2
HRSG Stack, ppmvd @ 15% O_2	12	12	12 0	12.0
HRSG Stack Emission rate (lb/hr)	95 4	91.2	87.7	82.3
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole wgt CO) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj for ppm)]				
Basis, ppmvd	20	20	20	20
Moisture (%)	10 6	11 21	11 68	12 18
Turbine Flow (acfm)	2,538,306	2,464,273	2,403,828	2,316,007
Turbine Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
HRSG Exhaust Temperature (°F)	297	295	294	294
Bypass/HRSG stack emission rate (lb/hr)- provided	68.1	64 7	62 1	58.9

Table A-10. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 28	59 °F Case 26	75 °F Case 24	95 °F Case 22
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x 2116.8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3.5
Moisture (%)	10.60	11.21	11.68	12.18
Turbine Flow (acfm)	11.19	11.06	11.00	11.00
Turbine Exhaust Temperature (°F)	2,538,306	2,464,273	2,403,828	2,316,007
HRSG Exhaust Temperature (°F)	1,074	1,098	1,113	1,131
Bypass/HRSG stack emission rate (lb/hr)- provided	7.62	7.28	7.04	6.70
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	103.1	98.6	94.9	89.1
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	10.31	9.86	9.49	8.91
Lead				
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14
Emission rate (lb/hr)	0.0265	0.0253	0.0244	0.0229

Note: ppmvd= parts per million, volume dry, O_2= oxygen

Source. GE, 2000 - CT Performance Data

Table A-11 Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 32	59 °F Case 31	75 °F Case 30	95 °F Case 29
Combustion Turbine Performance				
Net power output (MW)	141.5	135.0	129.1	119.1
Net heat rate (Btu/kWh, LHV)	10,654	10,730	10,866	11,138
(Btu/kWh, HHV)	11,293	11,373	11,518	11,807
Heat Input (MMBtu/hr, LHV)	1,508	1,449	1,403	1,327
(MMBtu/hr, HHV)	1,598	1,536	1,487	1,406
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	18,387	18,387	18,387	18,387
(Btu/lb, HHV)	19,490	19,490	19,490	19,490
(HHV/LHV)	1.060	1.060	1.060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	3,024,000	2,936,000	2,871,000	2,758,000
- provided	3,024,000	2,936,000	2,871,000	2,758,000
Temperature (°F)	1,121	1,137	1,149	1,166
Moisture (% Vol.)	10.23	10.68	11.06	11.54
Oxygen (% Vol.)	11.22	11.21	11.22	11.25
Molecular Weight	28.44	28.38	28.33	28.27
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,508	1,449	1,403	1,327
Heat content (Btu/lb, LHV)	18,387	18,387	18,387	18,387
Fuel usage (lb/hr)- calculated	81,993	78,784	76,298	72,154
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
CT/Bypass Stack Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,024,000	2,936,000	2,871,000	2,758,000
Temperature (°F)	1,121	1,137	1,149	1,166
Molecular weight	28.44	28.38	28.33	28.27
Volume flow (acfm)- calculated	2,045,011	2,009,479	1,983,445	1,929,486
(ft^3/s)- calculated	34,084	33,491	33,057	32,158
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	89.7	88.1	87.0	84.6
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	3,024,000	2,936,000	2,871,000	2,758,000
HRSG Stack Temperature (°F)	271	274	276	278
Molecular weight	28.44	28.38	28.33	28.27
CT volume flow (acfm)	945,414	923,329	907,281	875,151
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	55.6	54.3	53.3	51.4

Note. Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft², 14.7 lb/ft³

Source: GE, 2000

Table A-12 Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature 35 °F Case 32	59 °F Case 31	75 °F Case 30	95 °F Case 29
Particulate from CT and SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a PM_{10} (front half) (lb/hr)				
CT- provided	17.0	17.0	17.0	17 0
b PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	82 0	78 8	76 3	72 2
Conversion (%) from SO_2 to SO_3	9 8	9 8	9.8	9 8
MW SO_3/ SO_2 (80/64)	1 3	1 3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	16 57	15.92	15 42	14 58
Total CT/Bypass stack emission rate (lb/hr) [a]	17.0	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	33 6	32.9	32 4	31.6
(lb/mmBtu, HHV)	0 0208	0 0212	0 0215	0 0222
Sulfur Dioxide				
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100				
Fuel oil Sulfur Content	0 05%	0 05%	0 05%	0 05%
Fuel oil use (lb/hr)	81,993	78,784	76,298	72,154
lb SO2 / lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	82.0	78.8	76 3	72.2
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20 9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116 8 lb/ft^2 x Volume flow (acfm) x 46 (mole wgt NOx) x 60 min/hr / [1545 x (CT temp (°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @15% O_2	42	42	42	42
Moisture (%)	10 23	10 68	11 06	11.54
Oxygen (%)	11.22	11.21	11.22	11.25
Turbine Flow (acfm)	2,045,011	2,009,479	1,983,445	1,929,486
Turbine Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
CT/DB Emission rate (lb/hr)	262 6	252 6	244 5	231 2
CT/Bypasss Stack, ppmvd @ 15% O_2	42	42	42	42
CT/Bypass Stack Emission rate (lb/hr)	262 6	252 6	244.5	231 2
HRSG Stack, ppmvd @ 15% O_2	12 0	12 0	12 0	12 0
HRSG Stack Emission rate (lb/hr)	75 0	72.2	69 9	66 1
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116 8 lb/ft^2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	20	20	20	20
Moisture (%)	10 23	10 68	11 06	11 54
Turbine Flow (acfm)	2,045,011	2,009,479	1,983,445	1,929,486
Turbine Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
HRSG Exhaust Temperature (°F)	271	274	276	278
Bypass/HRSG stack emission rate (lb/hr)- provided	53 5	51 7	50.5	48.3

Table A-12 Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 32	59 °F Case 31	75 °F Case 30	95 °F Case 29
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x 2116 8 lb/ft^2 x Volume flow (acfm) x 16 (mole wgt as methane) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3.5	3.5	3 5
Moisture (%)	10 23	10 68	11.06	11 54
Turbine Flow (acfm)	11.22	11 21	11.22	11 25
Turbine Exhaust Temperature (°F)	2,045,011	2,009,479	1,983,445	1,929,486
HRSG Exhaust Temperature (°F)	1,121	1,137	1,149	1,166
Bypass/HRSG stack emission rate (lb/hr)- provided	5 95	5.79	5.67	5.46
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	82 0	78.8	76 3	72.2
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	8 20	7.88	7.63	7.22
Lead				
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14
Emission rate (lb/hr)	0 0211	0.0203	0.0196	0 0186

Note. ppmvd= parts per million, volume dry, O2= oxygen

Source: GE, 2000 - CT Performance Data

Table A-13. Design Information and Stack Parameters for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 36	59 °F Case 35	75 °F Case 34	95 °F Case 33
Combustion Turbine Performance				
Net power output (MW)	93.8	89.5	85.6	78.9
Net heat rate (Btu/kWh, LHV)	12,685	12,867	13,069	13,453
(Btu/kWh, HHV)	13,446	13,639	13,853	14,260
Heat Input (MMBtu/hr, LHV)	1,190	1,152	1,119	1,062
(MMBtu/hr, HHV)	1,261	1,221	1,186	1,125
Relative Humidity (%)	20	60	60	50
Fuel heating value (Btu/lb, LHV)	18,387	18,387	18,387	18,387
(Btu/lb, HHV)	19,490	19,490	19,490	19,490
(HHV/LHV)	1.060	1.060	1 060	1.060
CT Exhaust Flow				
Mass Flow (lb/hr)- with no margin	2,487,000	2,435,000	2,389,000	2,323,000
- provided	2,487,000	2,435,000	2,389,000	2,323,000
Temperature (°F)	1,168	1,182	1,193	1,200
Moisture (% Vol.)	9.29	9.77	10 17	10 6
Oxygen (% Vol)	11.76	11.76	11.77	11.86
Molecular Weight	28.51	28 46	28 40	28.34
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,190	1,152	1,119	1,062
Heat content (Btu/lb, LHV)	18,387	18,387	18,387	18,387
Fuel usage (lb/hr)- calculated	64,720	62,637	60,847	57,736
CT/Bypass and HRSG Stack				
CT/Bypass-Stack height (ft)	80	80	80	80
Diameter (ft)	22	22	22	22
HRSG - Stack Height (ft)	120	120	120	120
Diameter (ft)	19	19	19	19
Turbine Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116 8] / 60 min/hr				
Mass flow (lb/hr)	2,487,000	2,435,000	2,389,000	2,323,000
Temperature (°F)	1,168	1,182	1,193	1,200
Molecular weight	28.51	28.46	28 40	28 34
Volume flow (acfm)- calculated	1,727,369	1,709,200	1,691,211	1,654,983
(ft^3/s)- calculated	28,789	28,487	28,187	27,583
Diameter (ft)	22	22	22	22
Velocity (ft/sec)- calculated	75 7	74.9	74.2	72 6
Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min				
Mass flow (lb/hr)	2,487,000	2,435,000	2,389,000	2,323,000
HRSG Stack Temperature (°F)	256	259	264	268
Molecular weight	28 51	28.46	28.40	28 34
CT volume flow (acfm)	759,385	748,426	740,736	725,501
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	44 6	44 0	43.5	42 6

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116 8 lb(force)/ft², 14.7 lb/ft³

Source: GE, 2000

Table A-14. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature 35 °F Case 36	59 °F Case 35	75 °F Case 34	95 °F Case 33
Particulate from CT and SCR				
Total PM_{10} = PM_{10} (front half) + PM_{10} ($(NH_4)_2SO_4$) from SCR only				
a. PM_{10} (front half) (lb/hr)				
CT- provided	17.0	17.0	17.0	17.0
b. PM_{10} ($(NH_4)_2SO_4$) from SCR only = Sulfur trioxide from conversion of SO_2 converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x conversion of SO_2 to SO_3 x lb SO_3/lb SO_2 x conversion of SO_3 to $(NH_4)_2SO_4$ x lb $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	64.7	62.6	60.8	57.7
Conversion (%) from SO_2 to SO_3	9.8	9.8	9.8	9.8
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7	1.7
SCR Particulate (lb/hr)- calculated	13.08	12.66	12.30	11.67
Total CT/Bypass stack emission rate (lb/hr) [a]	17.0	17.0	17.0	17.0
Total HRSG stack emission rate (lb/hr) [a + b]	30.1	29.7	29.3	28.7
(lb/mmBtu, HHV)	0.0238	0.0243	0.0247	0.0255
Sulfur Dioxide				
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100				
Fuel oil Sulfur Content	0.05%	0.05%	0.05%	0.05%
Fuel oil use (lb/hr)	64,720	62,637	60,847	57,736
lb SO2 / lb S (64/32)	2	2	2	2
Bypass/HRSG stack emission rate (lb/hr)- calculated	64.7	62.6	60.8	57.7
Nitrogen Oxides				
NOx (lb/hr) = NOx (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp (°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT/DB, ppmvd @15% O_2	42	42	42	42
Moisture (%)	9.29	9.77	10.17	10.6
Oxygen (%)	11.76	11.76	11.77	11.86
Turbine Flow (acfm)	1,727,369	1,709,200	1,691,211	1,654,983
Turbine Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
CT/DB Emission rate (lb/hr)	205.6	198.9	192.9	183.2
CT/Bypasss Stack, ppmvd @ 15% O_2	42	42	42	42
CT/Bypass Stack Emission rate (lb/hr)	205.6	198.9	192.9	183.2
HRSG Stack, ppmvd @ 15% O_2	12	12	12.0	12.0
HRSG Stack Emission rate (lb/hr)	58.7	56.8	55.1	52.3
Carbon Monoxide				
CO (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole wgt CO) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	20	20	20	20
Moisture (%)	9.29	9.77	10.17	10.6
Turbine Flow (acfm)	1,727,369	1,709,200	1,691,211	1,654,983
Turbine Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
HRSG Exhaust Temperature (°F)	29	28	28	28
Bypass/HRSG stack emission rate (lb/hr)- provided	44.3	43.2	42.3	41.0

Table A-14. Maximum Emissions for Criteria Pollutants for FPL Martin Unit 8 Combined-Cycle Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Turbine Inlet Temperature			
	35 °F Case 36	59 °F Case 35	75 °F Case 34	95 °F Case 33
Volatile Organic Compounds				
VOCs (lb/hr) = VOC(ppmvd) x 2116 8 lb/ft^2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp (°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	3.5	3 5	3 5	3 5
Moisture (%)	9 29	9 77	10 17	10 60
Turbine Flow (acfm)	11.76	11.76	11.77	11.86
Turbine Exhaust Temperature (°F)	1,727,369	1,709,200	1,691,211	1,654,983
HRSG Exhaust Temperature (°F)	1,168	1,182	1,193	1,200
Bypass/HRSG stack emission rate (lb/hr)- provided	4 88	4.79	4 71	4.59
Sulfuric Acid Mist				
Sulfuric Acid Mist (lb/hr)= SO_2 emission (lb/hr) x Conversion to H_2SO_4 (% by weight)/100				
CT SO_2 emission rate (lb/hr) - provided	64 7	62.6	60 8	57.7
CT Conversion to H_2SO_4 (% by weight) - provided	10	10	10	10
DB SO_2 emission rate (lb/hr) - provided	0	0	0	0
DB Conversion to H_2SO_4 (%) - provided	20	20	20	20
Bypass/HRSG stack emission rate (lb/hr)- calculated	6 47	6.26	6 08	5 77
Lead				
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14
Emission rate (lb/hr)	0 0167	0 0161	0.0157	0 0149

Note ppmvd= parts per million, volume dry, O_2= oxygen

Source: GE, 2000 - CT Performance Data

Table A-15. Regulated and Hazardous Air Pollutant Emission Factors and Emissions for FPL Martin Unit 8 Combined-Cycle Project when Firing Natural Gas

Parameter		Emission Rate (lb/hr) firing Natural Gas for Operating Conditions of Base Load (1)				Natural Gas Maximum Annual Emissions (TPY) (2)	
Ambient Temperature (°F)		59 °F	59 °F w/DB	80 °F w/DB Power Aug.	59 °F HP Mode	59 °F 1 CT/HRSG	59 °F 4 CTs/HRSGs
HIR (MMBtu/hr):		1,776	2,326	2,273	1,865		
Sulfuric acid mist		0.98	1.59	1.56	1.03	6 9	27.8
HAPs (Section 112(b) of Clean Air Act)							
1,3-Butadiene		0.000764	0 001000	0.000978	0 000802	0.00438	0 0175
Acetaldehyde		0.0711	0.0931	0.0909	0.0746	0 41	1.63
Acrolein		0 0114	0 0149	0.0146	0.0119	0 0652	0.261
Benzene		0 0213	0 0279	0.0273	0 0224	0.122	0.489
Ethylbenzene		0 0568	0.0744	0.0728	0.0597	0 326	1.304 .
Formadehyde		0 266	0 349	0 341	0.280	1.53	6.11
Naphthalene		0.00231	0 00302	0 00296	0.00242	0 0132	0 0530
Polycyclic Aromatic Hydrocarbons (PAH)	(3)	0 00391	0 00512	0 00500	0.00410	0 0224	0 0897
Propylene Oxide		0.0515	0 0675	0 0659	0.0541	0.295	1.182
Toluene		0 0586	0 0768	0.0750	0 0615	0.336	1.34
Xylene		0.114	0 149	0.146	0.119	0 652	2.61
Antimony		0.0	0 0	0.0	0 0	0.00	0.00
Arsenic		0.0	0 0	0.0	0.0	0.00	0 00
Beryllium		0.0	0 0	0.0	0 0	0 00	0.00
Cadmium		0.0	0 0	0.0	0 0	0 00	0 00
Chromium		0.0	0 0	0.0	0 0	0.00	0.00
Lead		0.0	0 0	0.0	0 0	0.00	0.00
Manganese		0 0	0 0	0.0	0 0	0 00	0.00
Mercury		0.0	0 0	0.0	0.0	0.00	0.00
Nickel		0 0	0 0	0 0	0 0	0.00	0 00
Selenium		0 0	0 0	0.0	0 0	0.00	0.00
HAPs (Total)		0 658	0 862	0 842	0.691	5.03	15 1

(1) Emissions based on the following emission factors and conversion factors for firing natural gas:

Emission Factors		Value	Reference
Sulfuric acid mist		5	%, Conversion of SO_2 to SO_3 in gas turbine
1,3-Butadiene	(a)	0 43	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Acetaldehyde		40	lb/10^{12} Btu, AP-42,Table 3.1-3. EPA 2000
Acrolein		6 4	lb/10^{12} Btu; AP-42,Table 3.1-3 EPA 2000
Benzene		12	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Ethylbenzene		32	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Formadehyde		150	lb/10^{12} Btu, AP-42,Table 3.1-3. EPA 2000 Database
Naphthalene		1.3	lb/10^{12} Btu, AP-42,Table 3 1-3. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		2.2	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Propylene Oxide	(a)	29	lb/10^{12} Btu; AP-42,Table 3.1-3 EPA 2000
Toluene		33	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000. Database
Xylene		64	lb/10^{12} Btu; AP-42,Table 3 1-3. EPA 2000
Antimony		0 00E+00	
Arsenic		0.00E+00	
Beryllium		0 00E+00	
Cadmium		0 00E+00	
Chromium		0 00E+00	
Lead		0.00E+00	
Manganese		0.00E+00	
Mercury		0 00E+00	
Nickel		0 00E+00	
Selenium		0 00E+00	

(a) Based on 1/2 the detection limit; expected emissions are lower

(2) Annual emissions based on ambient temperature of 59 °F firing natural gas for following hours:

0 at base load; CT only
8,760 at base load; CT with duct firing
0 at base load; CT with duct firing and power aug.
0 high power mode; CT only

(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

Table A-16 Regulated and Hazardous Air Pollutant Emission Factors and Emissions for FPL FPL Martin Unit 8 Combined-Cycle Project when Firing Distillate Fuel Oil

Parameter	Emission Rate (lb/hr) Firing Distillate Fuel Oil (1)	Maximum Annual Emissions (TPY)			
	Base Load	Distillate Fuel Oil (2)		Natural Gas (4)	Natural Gas and Fuel Oil (5)
Ambient Temperature (°F)	59 °F				
HIR (MMBtu/hr)	1,919	1 CT/HRSG	4 CTs/HRSGs	4 CTs/HRSGs	4 CTs/HRSGs
Sulfuric acid mist	9 9	2 46	9.9	27.8	36 1
HAPs (Section 112(b) of Clean Air Act)					
1,3-Butadiene	0 0307	0 0077	0 0307	0 0175	0 047
Acetaldehyde	0 00	0 00	0 00	1 63	1.5
Acrolein	0 00	0 00	0 00	0 261	0 25
Benzene	0 106	0 0264	0 1056	0 489	0 57
Ethylbenzene	0 00	0 00	0 00	1.304	1.23
Formadehyde	0 537	0 134	0 537	6 11	6 3
Naphthalene	0 0672	0 0168	0 0672	0 0530	0 117
Polycyclic Aromatic Hydrocarbons (PAH) (3)	0 0768	0 0192	0 0768	0 0897	0 16
Propylene Oxide	0 00	0 00	0 00	1.182	1.11
Toluene	0 00	0 00	0 00	1.34	1.3
Xylene	0 00	0.00	0 00	2 61	2 5
Antimony	0 00	0 00	0 00	0 00	0 0
Arsenic	0 0211	0 00528	0 0211	0 00	0 021
Beryllium	0 000595	0 000149	0 000595	0 00	0 00059
Cadmium	0 00921	0 00230	0 00921	0 00	0 0092
Chromium	0 0211	0.00528	0 0211	0 00	0 021
Lead	0.0269	0 00672	0 0269	0 00	0 027
Manganese	1.52	0 379	1.52	0 00	1 5
Mercury	0 00230	0 000576	0 00230	0 00	0 0023
Nickel	0 00883	0 00221	0 00883	0 00	0 0088
Selenium	0 0480	0 0120	0 0480	0 00	0 048
HAPs (Total)	2 47	0 824	2 47	15 1	16 7

(1) Emissions based on the following emission factors and conversion factors for firing distillate fuel oil:

Emission Factors		Value	Reference
Sulfuric acid mist		5	%, Conversion of SO_2 to SO_3 in gas turbine
1,3-Butadiene	(a)	16	lb/10^{12} Btu, AP-42,Table 3.1-4 EPA 2000
Acetaldehyde		0 0	
Acrolein		0 0	
Benzene		55	lb/10^{12} Btu, AP-42,Table 3 1-4 EPA 2000
Ethylbenzene		0 0	
Formadehyde		280	lb/10^{12} Btu, AP-42,Table 3 1-4 EPA 2000
Naphthalene		35	lb/10^{12} Btu, AP-42,Table 3.1-4 EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		40	lb/10^{12} Btu, AP-42,Table 3 1-4 EPA 2000
Propylene Oxide		0 0	
Toluene		0 0	
Xylene		0 0	
Antimony		0 0	
Arsenic	(a)	11	lb/10^{12} Btu, AP-42,Table 3 1-5 EPA 2000
Beryllium	(a)	0 31	lb/10^{12} Btu, AP-42,Table 3.1-5 EPA 2000
Cadmium		4 8	lb/10^{12} Btu; AP-42,Table 3 1-5. EPA 2000
Chromium		11	lb/10^{12} Btu, AP-42,Table 3 1-5 EPA 2000
Lead		14	lb/10^{12} Btu, AP-42,Table 3.1-5 EPA 2000
Manganese		790	lb/10^{12} Btu, AP-42,Table 3 1-5. EPA 2000
Mercury		1.2	lb/10^{12} Btu, AP-42,Table 3 1-5. EPA 2000
Nickel	(a)	4 6	lb/10^{12} Btu; AP-42,Table 3.1-5. EPA 2000
Selenium	(a)	25	lb/10^{12} Btu; AP-42,Table 3.1-5 EPA 2000

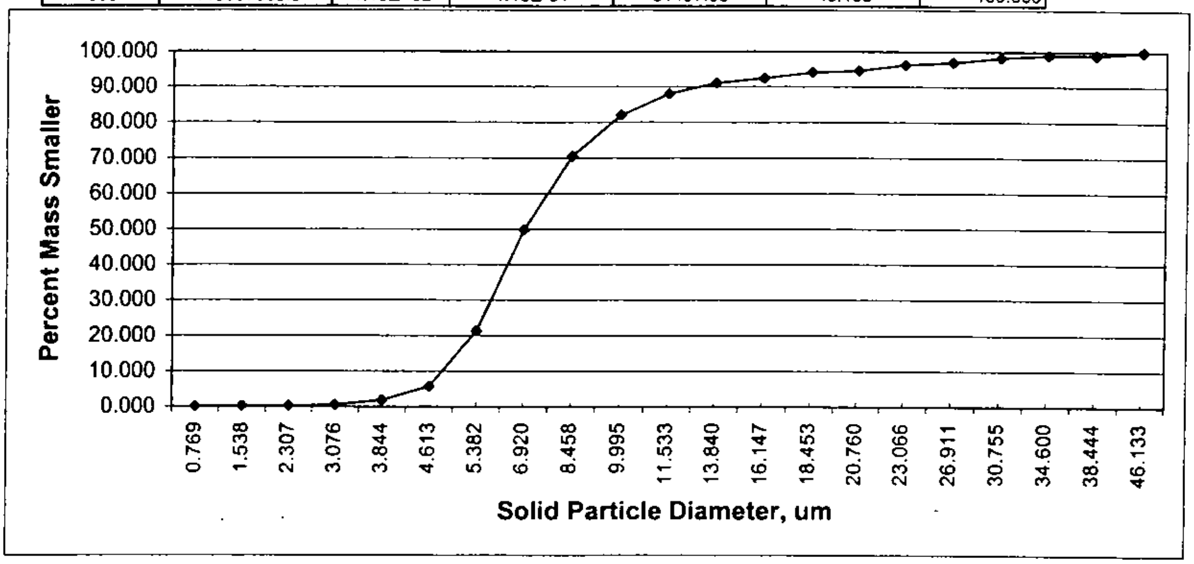
(a) Based on 1/2 the detection limit, expected emissions are lower.

(2) Annual emissions based on ambient temperature of 59 °F and firing fuel oil at base load for 500 hours
(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.
(4) Annual emissions based on maximum emissions presented for natural gas-firing
(5) Maximum total annual emissions based on 500 hours of firing fuel and remaining hours firing natural gas.

PM AND PM_{10} EMISSION RATE CALCULATIONS FOR COOLING TOWER

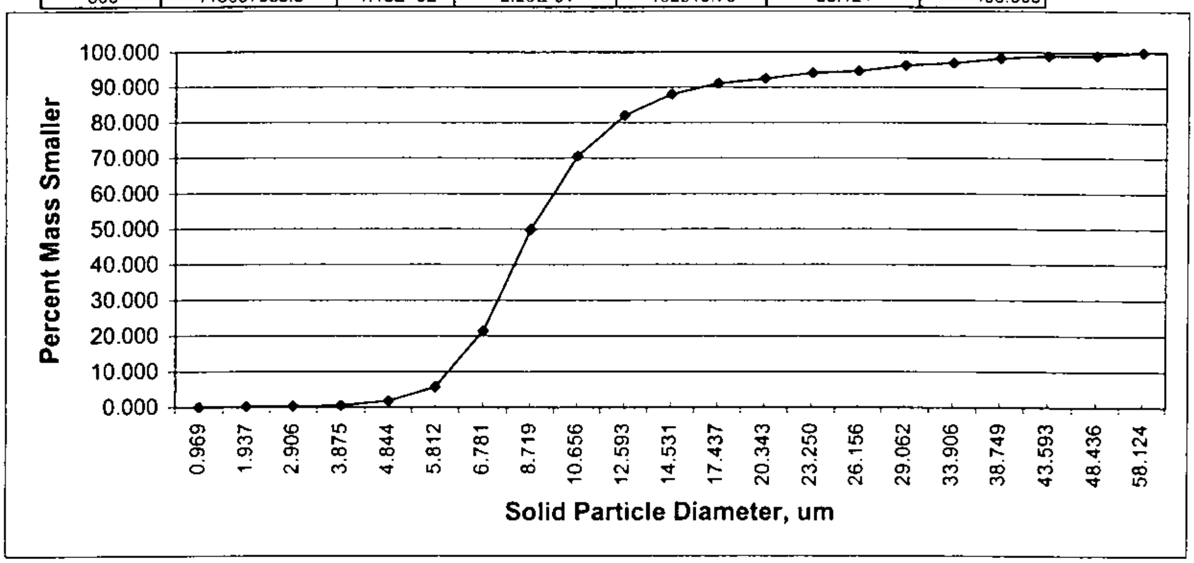
Resultant Solid Particulate Size Destribution (TDS = 1000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.24E-07	0.24	0.769	0.000
20	4188.8	4.19E-03	4.19E-06	1.90	1.538	0.196
30	14137.2	1.41E-02	1.41E-05	6.43	2.307	0.226
40	33510.3	3.35E-02	3.35E-05	15.23	3.076	0.514
50	65449.8	6.54E-02	6.54E-05	29.75	3.844	1.816
60	113097.3	1.13E-01	1.13E-04	51.41	4.613	5.702
70	179594.4	1.80E-01	1.80E-04	81.63	5.382	21.348
90	381703.5	3.82E-01	3.82E-04	173.50	6.920	49.812
110	696910.0	6.97E-01	6.97E-04	316.78	8.458	70.509
130	1150346.5	1.15E+00	1.15E-03	522.88	9.995	82.023
150	1767145.9	1.77E+00	1.77E-03	803.25	11.533	88.012
180	3053628.1	3.05E+00	3.05E-03	1388.01	13.840	91.032
210	4849048.3	4.85E+00	4.85E-03	2204.11	16.147	92.468
240	7238229.5	7.24E+00	7.24E-03	3290.10	18.453	94.091
270	10305994.7	1.03E+01	1.03E-02	4684.54	20.760	94.689
300	14137166.9	1.41E+01	1.41E-02	6425.98	23.066	96.288
350	22449297.5	2.24E+01	2.24E-02	10204.23	26.911	97.011
400	33510321.6	3.35E+01	3.35E-02	15231.96	30.755	98.340
450	47712938.4	4.77E+01	4.77E-02	21687.70	34.600	99.071
500	65449846.9	6.54E+01	6.54E-02	29749.93	38.444	99.071
600	113097335.5	1.13E+02	1.13E-01	51407.88	46.133	100.000



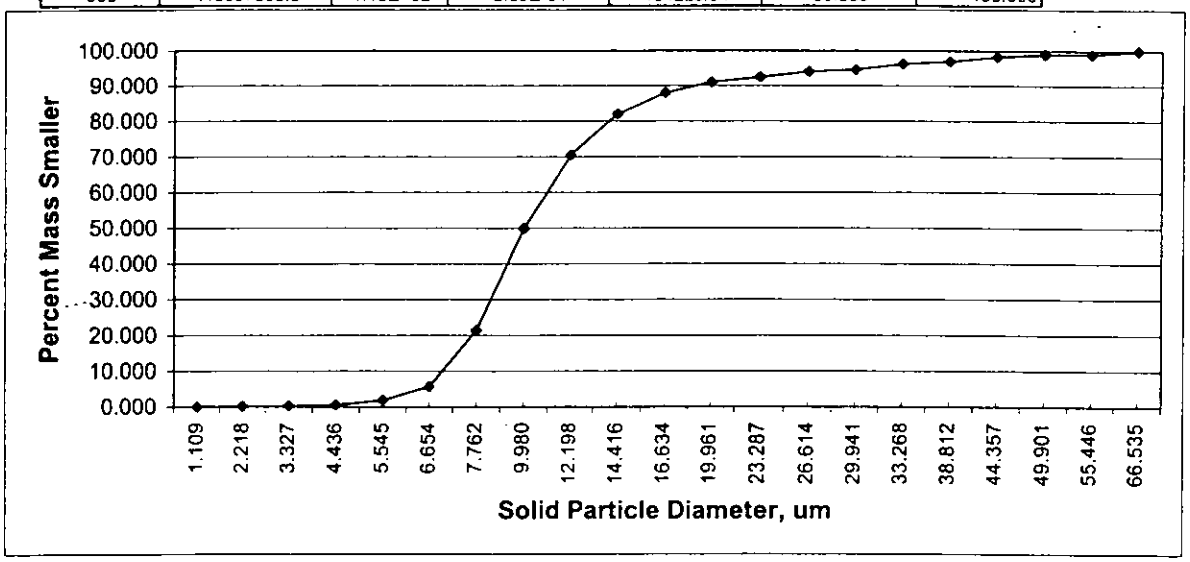
Resultant Solid Particulate Size Destribution (TDS = 2000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	1.05E-06	0.48	0.969	0.000
20	4188.8	4.19E-03	8.38E-06	3.81	1.937	0.196
30	14137.2	1.41E-02	2.83E-05	12.85	2.906	0.226
40	33510.3	3.35E-02	6.70E-05	30.46	3.875	0.514
50	65449.8	6.54E-02	1.31E-04	59.50	4.844	1.816
60	113097.3	1.13E-01	2.26E-04	102.82	5.812	5.702
70	179594.4	1.80E-01	3.59E-04	163.27	6.781	21.348
90	381703.5	3.82E-01	7.63E-04	347.00	8.719	49.812
110	696910.0	6.97E-01	1.39E-03	633.55	10.656	70.509
130	1150346.5	1.15E+00	2.30E-03	1045.77	12.593	82.023
150	1767145.9	1.77E+00	3.53E-03	1606.50	14.531	88.012
180	3053628.1	3.05E+00	6.11E-03	2776.03	17.437	91.032
210	4849048.3	4.85E+00	9.70E-03	4408.23	20.343	92.468
240	7238229.5	7.24E+00	1.45E-02	6580.21	23.250	94.091
270	10305994.7	1.03E+01	2.06E-02	9369.09	26.156	94.689
300	14137166.9	1.41E+01	2.83E-02	12851.97	29.062	96.288
350	22449297.5	2.24E+01	4.49E-02	20408.45	33.906	97.011
400	33510321.6	3.35E+01	6.70E-02	30463.93	38.749	98.340
450	47712938.4	4.77E+01	9.54E-02	43375.40	43.593	99.071
500	65449846.9	6.54E+01	1.31E-01	59499.86	48.436	99.071
600	113097335.5	1.13E+02	2.26E-01	102815.76	58.124	100.000



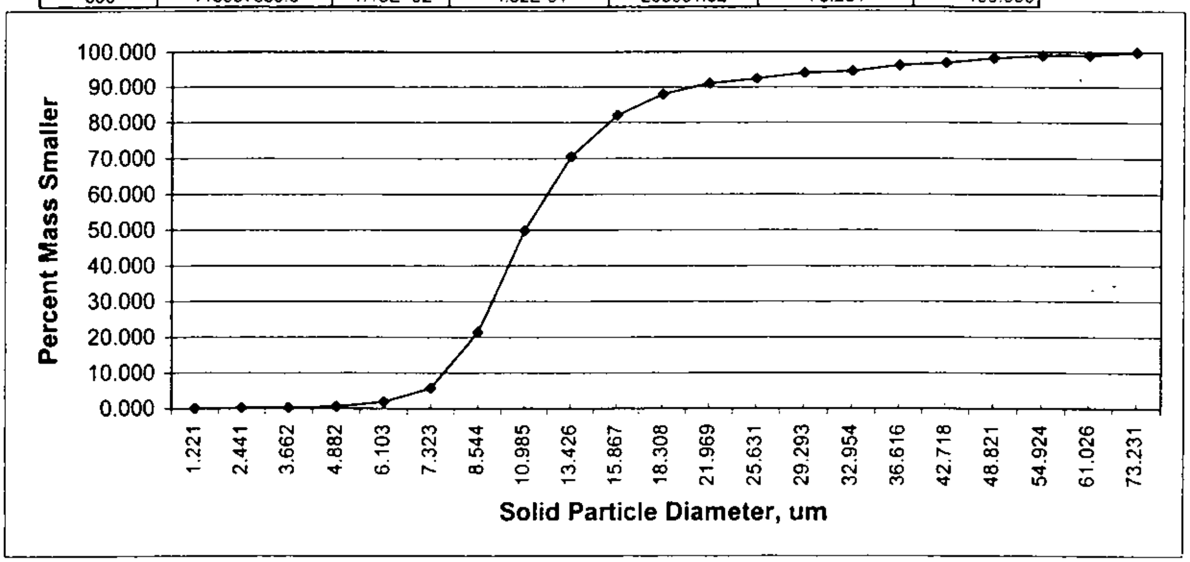
Resultant Solid Particulate Size Destribution (TDS = 3000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	1.57E-06	0.71	1.109	0.000
20	4188.8	4.19E-03	1.26E-05	5.71	2.218	0.196
30	14137.2	1.41E-02	4.24E-05	19.28	3.327	0 226
40	33510.3	3.35E-02	1.01E-04	45.70	4.436	0.514
50	65449.8	6.54E-02	1.96E-04	89.25	5.545	1.816
60	113097.3	1.13E-01	3.39E-04	154.22	6.654	5.702
70	179594.4	1.80E-01	5.39E-04	244.90	7.762	21.348
90	381703.5	3.82E-01	1.15E-03	520.50	9.980	49.812
110	696910.0	6.97E-01	2.09E-03	950.33	12 198	70.509
130	1150346.5	1.15E+00	3.45E-03	1568.65	14.416	82.023
150	1767145.9	1.77E+00	5.30E-03	2409.74	16.634	88.012
180	3053628.1	3.05E+00	9.16E-03	4164.04	19.961	91.032
210	4849048.3	4.85E+00	1.45E-02	6612.34	23.287	92.468
240	7238229.5	7.24E+00	2.17E-02	9870.31	26.614	94.091
270	10305994.7	1.03E+01	3.09E-02	14053.63	29.941	94.689
300	14137166.9	1.41E+01	4.24E-02	19277.95	33.268	96.288
350	22449297.5	2.24E+01	6.73E-02	30612.68	38.812	97.011
400	33510321.6	3.35E+01	1.01E-01	45695.89	44.357	98.340
450	47712938.4	4.77E+01	1.43E-01	65063.10	49.901	99.071
500	65449846.9	6.54E+01	1.96E-01	89249.79	55.446	99.071
600	113097335.5	1.13E+02	3.39E-01	154223.64	66.535	100.000



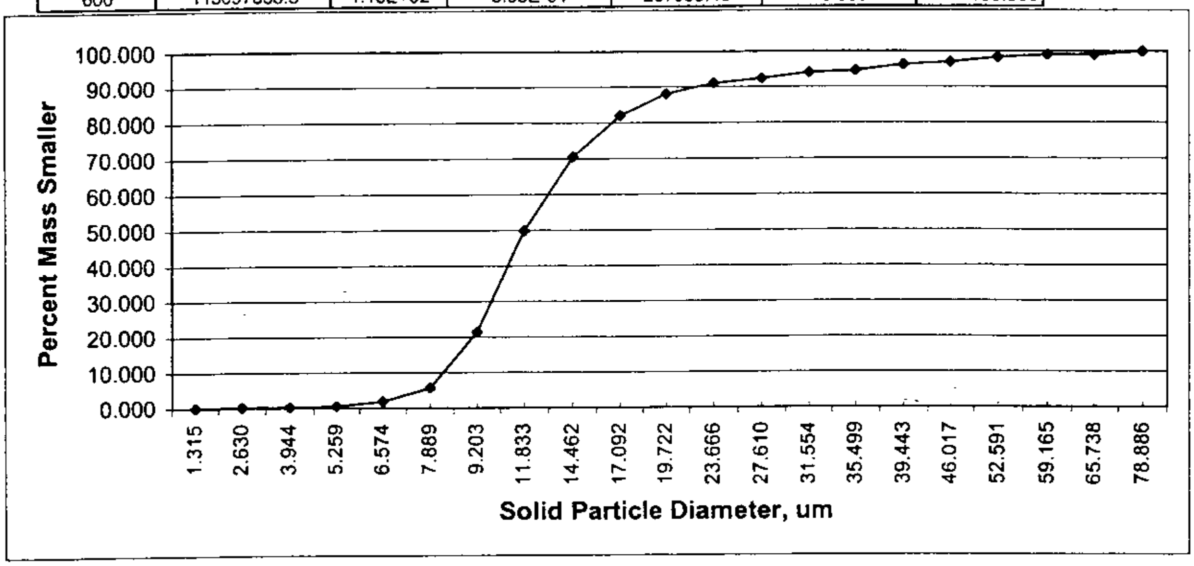
Resultant Solid Particulate Size Destribution (TDS = 4000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	2.09E-06	0.95	1.221	0.000
20	4188.8	4.19E-03	1.68E-05	7.62	2.441	0.196
30	14137.2	1.41E-02	5.65E-05	25.70	3.662	0.226
40	33510.3	3.35E-02	1.34E-04	60.93	4.882	0.514
50	65449.8	6.54E-02	2.62E-04	119.00	6.103	1.816
60	113097.3	1.13E-01	4.52E-04	205.63	7.323	5.702
70	179594.4	1.80E-01	7.18E-04	326.54	8.544	21.348
90	381703.5	3.82E-01	1.53E-03	694.01	10.985	49.812
110	696910.0	6.97E-01	2.79E-03	1267.11	13.426	70.509
130	1150346.5	1.15E+00	4.60E-03	2091.54	15.867	82.023
150	1767145.9	1.77E+00	7.07E-03	3212.99	18.308	88.012
180	3053628.1	3.05E+00	1.22E-02	5552.05	21.969	91.032
210	4849048.3	4.85E+00	1.94E-02	8816.45	25.631	92.468
240	7238229.5	7.24E+00	2.90E-02	13160.42	29.293	94.091
270	10305994.7	1.03E+01	4.12E-02	18738.17	32.954	94.689
300	14137166.9	1.41E+01	5.65E-02	25703.94	36.616	96.288
350	22449297.5	2.24E+01	8.98E-02	40816.90	42.718	97.011
400	33510321.6	3.35E+01	1.34E-01	60927.86	48.821	98.340
450	47712938.4	4.77E+01	1.91E-01	86750.80	54.924	99.071
500	65449846.9	6.54E+01	2.62E-01	118999.72	61.026	99.071
600	113097335.5	1.13E+02	4.52E-01	205631.52	73.231	100.000



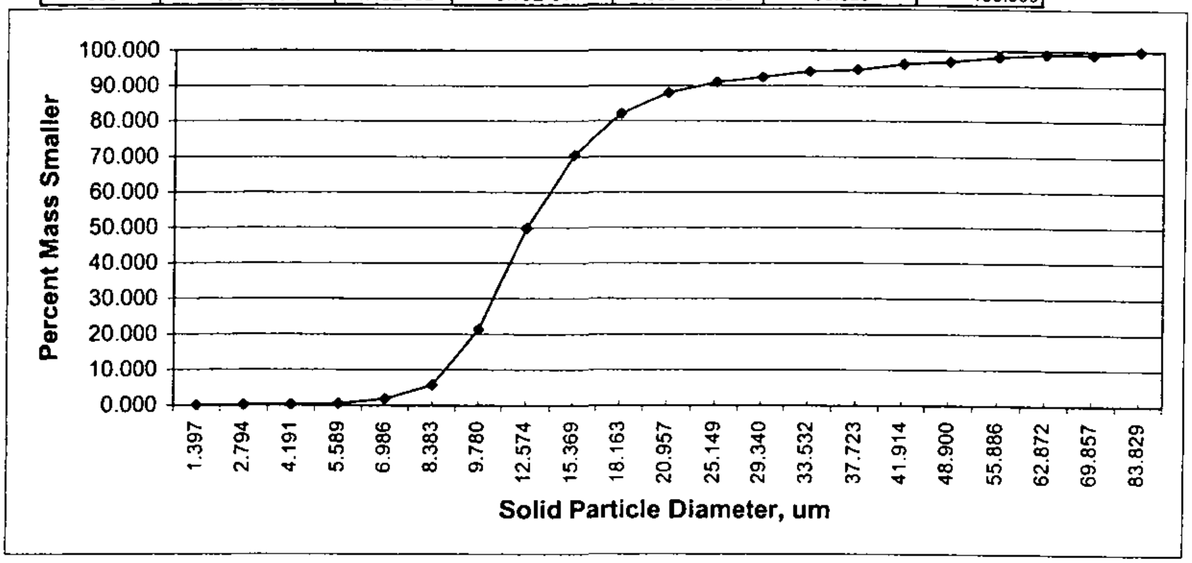
Resultant Solid Particulate Size Destribution (TDS = 5000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	2.62E-06	1.19	1.315	0.000
20	4188.8	4.19E-03	2.09E-05	9.52	2.630	0.196
30	14137.2	1.41E-02	7.07E-05	32.13	3.944	0.226
40	33510.3	3.35E-02	1.68E-04	76.16	5.259	0.514
50	65449.8	6.54E-02	3.27E-04	148.75	6.574	1.816
60	113097.3	1.13E-01	5.65E-04	257.04	7.889	5.702
70	179594.4	1.80E-01	8.98E-04	408.17	9.203	21.348
90	381703.5	3.82E-01	1.91E-03	867.51	11.833	49.812
110	696910.0	6.97E-01	3.48E-03	1583.89	14.462	70.509
130	1150346.5	1.15E+00	5.75E-03	2614.42	17.092	82.023
150	1767145.9	1.77E+00	8.84E-03	4016.24	19.722	88.012
180	3053628.1	3.05E+00	1.53E-02	6940.06	23.666	91.032
210	4849048.3	4.85E+00	2.42E-02	11020.56	27.610	92.468
240	7238229.5	7.24E+00	3.62E-02	16450.52	31.554	94.091
270	10305994.7	1.03E+01	5.15E-02	23422.72	35.499	94.689
300	14137166.9	1.41E+01	7.07E-02	32129.92	39.443	96.288
350	22449297.5	2.24E+01	1.12E-01	51021.13	46.017	97.011
400	33510321.6	3.35E+01	1.68E-01	76159.82	52.591	98.340
450	47712938.4	4.77E+01	2.39E-01	108438.50	59.165	99.071
500	65449846.9	6.54E+01	3.27E-01	148749.65	65.738	99.071
600	113097335.5	1.13E+02	5.65E-01	257039.40	78.886	100.000



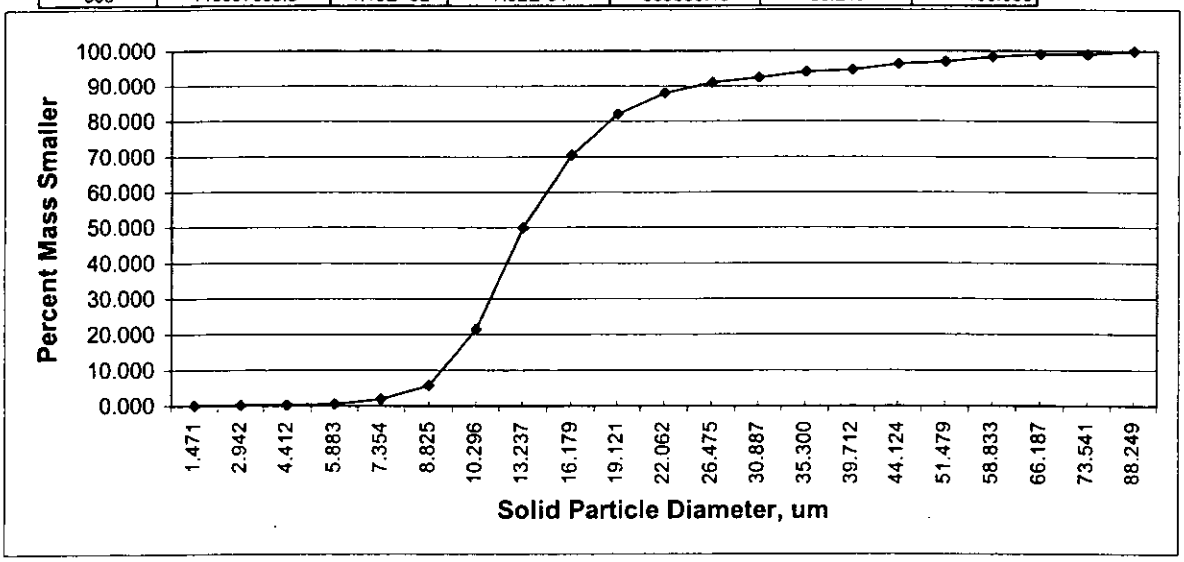
Resultant Solid Particulate Size Destribution (TDS = 6000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	3.14E-06	1.43	1.397	0.000
20	4188.8	4.19E-03	2.51E-05	11.42	2.794	0.196
30	14137.2	1.41E-02	8.48E-05	38.56	4.191	0 226
40	33510.3	3.35E-02	2.01E-04	91.39	5.589	0.514
50	65449.8	6.54E-02	3.93E-04	178.50	6.986	1.816
60	113097.3	1.13E-01	6.79E-04	308.45	8.383	5.702
70	179594.4	1.80E-01	1.08E-03	489 80	9.780	21.348
90	381703.5	3.82E-01	2.29E-03	1041.01	12.574	49.812
110	696910.0	6.97E-01	4.18E-03	1900.66	15.369	70.509
130	1150346.5	1.15E+00	6.90E-03	3137.31	18.163	82.023
150	1767145.9	1.77E+00	1.06E-02	4819.49	20.957	88.012
180	3053628.1	3.05E+00	1.83E-02	8328.08	25.149	91.032
210	4849048.3	4.85E+00	2.91E-02	13224.68	29.340	92.468
240	7238229.5	7.24E+00	4.34E-02	19740.63	33.532	94.091
270	10305994.7	1.03E+01	6.18E-02	28107.26	37.723	94.689
300	14137166.9	1.41E+01	8.48E-02	38555.91	41.914	96.288
350	22449297.5	2.24E+01	1.35E-01	61225.36	48.900	97.011
400	33510321.6	3.35E+01	2.01E-01	91391.79	55.886	98.340
450	47712938.4	4.77E+01	2.86E-01	130126.20	62.872	99.071
500	65449846.9	6.54E+01	3.93E-01	178499.58	69.857	99.071
600	113097335.5	1.13E+02	6.79E-01	308447.28	83.829	100.000



Resultant Solid Particulate Size Destribution (TDS = 7000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	3.67E-06	1.67	1.471	0.000
20	4188.8	4.19E-03	2.93E-05	13.33	2.942	0.196
30	14137.2	1.41E-02	9.90E-05	44.98	4.412	0.226
40	33510.3	3.35E-02	2.35E-04	106.62	5.883	0.514
50	65449.8	6.54E-02	4.58E-04	208.25	7.354	1.816
60	113097.3	1.13E-01	7.92E-04	359.86	8.825	5.702
70	179594.4	1.80E-01	1.26E-03	571.44	10.296	21.348
90	381703.5	3.82E-01	2.67E-03	1214.51	13.237	49.812
110	696910.0	6.97E-01	4.88E-03	2217.44	16.179	70.509
130	1150346.5	1.15E+00	8.05E-03	3660.19	19.121	82.023
150	1767145.9	1.77E+00	1.24E-02	5622.74	22.062	88.012
180	3053628.1	3.05E+00	2.14E-02	9716.09	26.475	91.032
210	4849048.3	4.85E+00	3.39E-02	15428.79	30.887	92.468
240	7238229.5	7.24E+00	5.07E-02	23030.73	35.300	94.091
270	10305994.7	1.03E+01	7.21E-02	32791.80	39.712	94.689
300	14137166.9	1.41E+01	9.90E-02	44981.89	44.124	96.288
350	22449297.5	2.24E+01	1.57E-01	71429.58	51.479	97.011
400	33510321.6	3.35E+01	2.35E-01	106623.75	58.833	98.340
450	47712938.4	4.77E+01	3.34E-01	151813.89	66.187	99.071
500	65449846.9	6.54E+01	4.58E-01	208249.51	73.541	99.071
600	113097335.5	1.13E+02	7.92E-01	359855.16	88.249	100.000

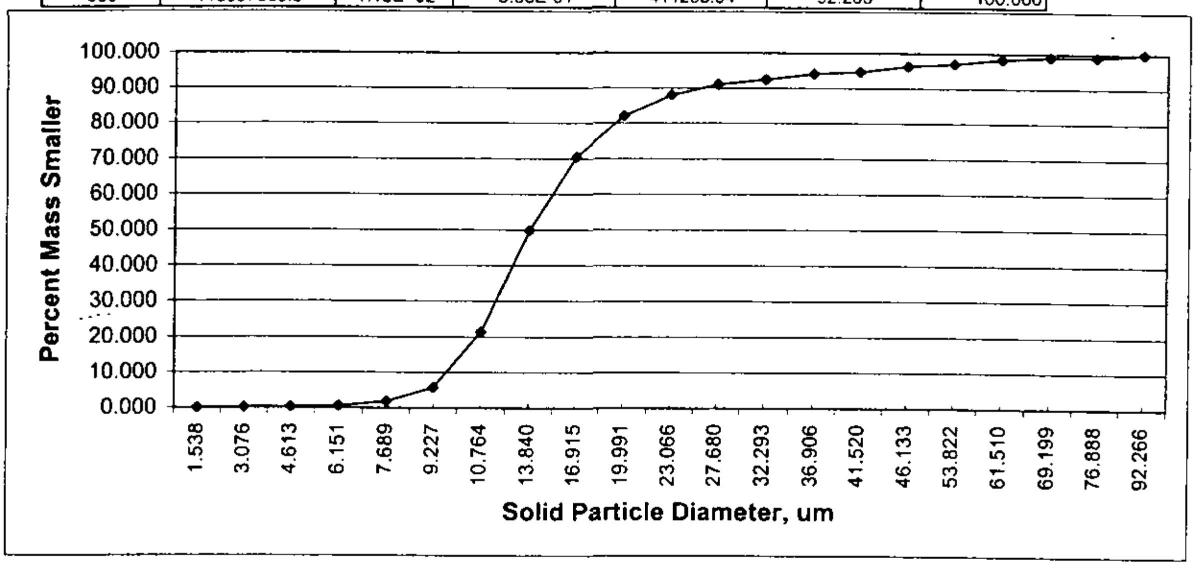


Resultant Solid Particulate Size Destribution (TDS = 9000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.03E-06	1.83	1.518	0.000
20	4188.8	4.19E-03	3.23E-05	14.66	3.037	0.196
30	14137.2	1.41E-02	1.09E-04	49.48	4.555	0.226
40	33510.3	3.35E-02	2.58E-04	117.29	6.073	0.514
50	65449.8	6.54E-02	5.04E-04	229.07	7.591	1.816
60	113097.3	1.13E-01	8.71E-04	395.84	9.110	5.702
70	179594.4	1.80E-01	1.38E-03	628.58	10.628	21.348
90	381703.5	3.82E-01	2.94E-03	1335.96	13.665	49.812
110	696910.0	6.97E-01	5.37E-03	2439.18	16.701	70.509
130	1150346.5	1.15E+00	8.86E-03	4026.21	19.738	82.023
150	1767145.9	1.77E+00	1.36E-02	6185.01	22.774	88.012
180	3053628.1	3.05E+00	2.35E-02	10687.70	27.329	91.032
210	4849048.3	4.85E+00	3.73E-02	16971.67	31.884	92.468
240	7238229.5	7.24E+00	5.57E-02	25333.80	36.439	94.091
270	10305994.7	1.03E+01	7.94E-02	36070.98	40.994	94.689
300	14137166.9	1.41E+01	1.09E-01	49480.08	45.549	96.288
350	22449297.5	2.24E+01	1.73E-01	78572.54	53.140	97.011
400	33510321.6	3.35E+01	2.58E-01	117286.13	60.732	98.340
450	47712938.4	4.77E+01	3.67E-01	166995.28	68.323	99.071
500	65449846.9	6.54E+01	5.04E-01	229074.46	75.915	99.071
600	113097335.5	1.13E+02	8.71E-01	395840.67	91.098	100.000

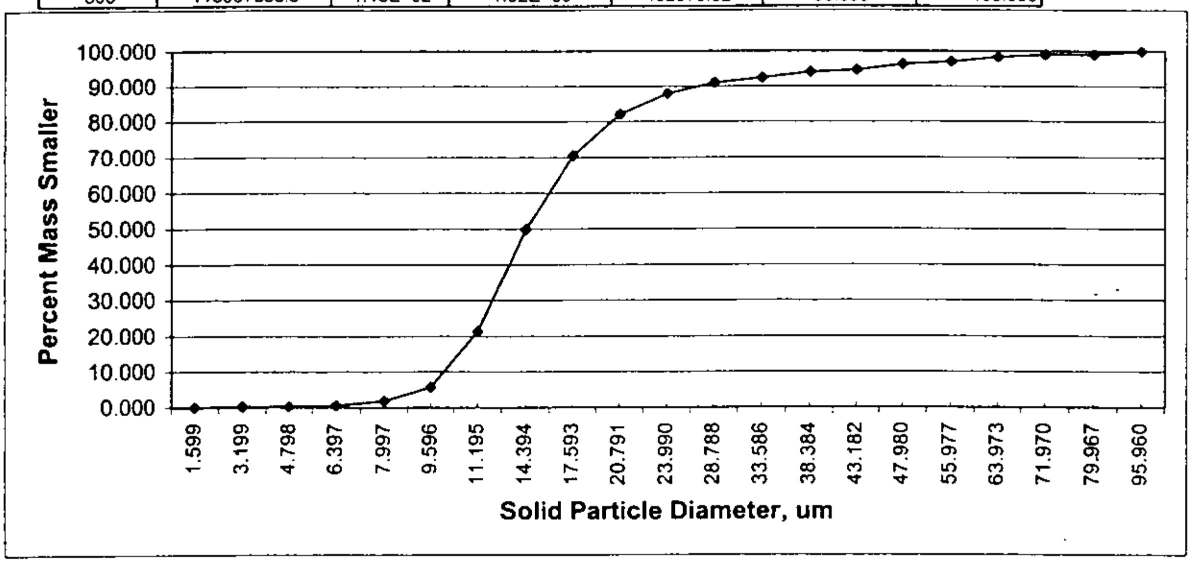
Resultant Solid Particulate Size Destribution (TDS = 8000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.19E-06	1.90	1.538	0.000
20	4188.8	4.19E-03	3.35E-05	15.23	3.076	0.196
30	14137.2	1.41E-02	1.13E-04	51.41	4.613	0.226
40	33510.3	3.35E-02	2.68E-04	121.86	6.151	0.514
50	65449.8	6.54E-02	5.24E-04	238.00	7.689	1.816
60	113097.3	1.13E-01	9.05E-04	411.26	9.227	5.702
70	179594.4	1.80E-01	1.44E-03	653.07	10.764	21.348
90	381703.5	3.82E-01	3.05E-03	1388.01	13.840	49.812
110	696910.0	6.97E-01	5.58E-03	2534.22	16.915	70.509
130	1150346.5	1.15E+00	9.20E-03	4183.08	19.991	82.023
150	1767145.9	1.77E+00	1.41E-02	6425.98	23.066	88.012
180	3053628.1	3.05E+00	2.44E-02	11104.10	27.680	91.032
210	4849048.3	4.85E+00	3.88E-02	17632.90	32.293	92.468
240	7238229.5	7.24E+00	5.79E-02	26320.83	36.906	94.091
270	10305994.7	1.03E+01	8.24E-02	37476.34	41.520	94.689
300	14137166.9	1.41E+01	1.13E-01	51407.88	46.133	96.288
350	22449297.5	2.24E+01	1.80E-01	81633.81	53.822	97.011
400	33510321.6	3.35E+01	2.68E-01	121855.72	61.510	98.340
450	47712938.4	4.77E+01	3.82E-01	173501.59	69.199	99.071
500	65449846.9	6.54E+01	5.24E-01	237999.44	76.888	99.071
600	113097335.5	1.13E+02	9.05E-01	411263.04	92.266	100.000



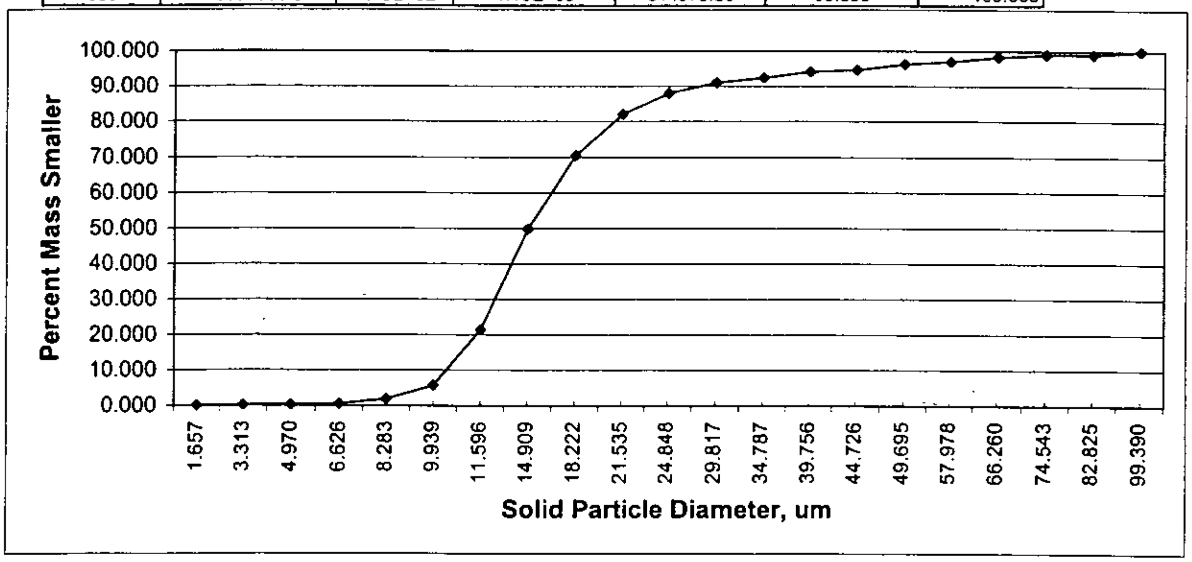
Resultant Solid Particulate Size Destribution (TDS = 9000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.71E-06	2.14	1.599	0.000
20	4188.8	4.19E-03	3.77E-05	17.14	3.199	0.196
30	14137.2	1.41E-02	1.27E-04	57.83	4.798	0.226
40	33510.3	3.35E-02	3.02E-04	137.09	6.397	0.514
50	65449.8	6.54E-02	5.89E-04	267.75	7.997	1.816
60	113097.3	1.13E-01	1.02E-03	462.67	9.596	5.702
70	179594.4	1.80E-01	1.62E-03	734.70	11.195	21.348
90	381703.5	3.82E-01	3.44E-03	1561.51	14.394	49.812
110	696910.0	6.97E-01	6.27E-03	2851.00	17.593	70.509
130	1150346.5	1.15E+00	1.04E-02	4705.96	20.791	82.023
150	1767145.9	1.77E+00	1.59E-02	7229.23	23.990	88.012
180	3053628.1	3.05E+00	2.75E-02	12492.11	28.788	91.032
210	4849048.3	4.85E+00	4.36E-02	19837.02	33.586	92.468
240	7238229.5	7.24E+00	6.51E-02	29610.94	38.384	94.091
270	10305994.7	1.03E+01	9.28E-02	42160.89	43.182	94.689
300	14137166.9	1.41E+01	1.27E-01	57833.86	47.980	96.288
350	22449297.5	2.24E+01	2.02E-01	91838.04	55.977	97.011
400	33510321.6	3.35E+01	3.02E-01	137087.68	63.973	98.340
450	47712938.4	4.77E+01	4.29E-01	195189.29	71.970	99.071
500	65449846.9	6.54E+01	5.89E-01	267749.37	79.967	99.071
600	113097335.5	1.13E+02	1.02E+00	462670.92	95.960	100.000



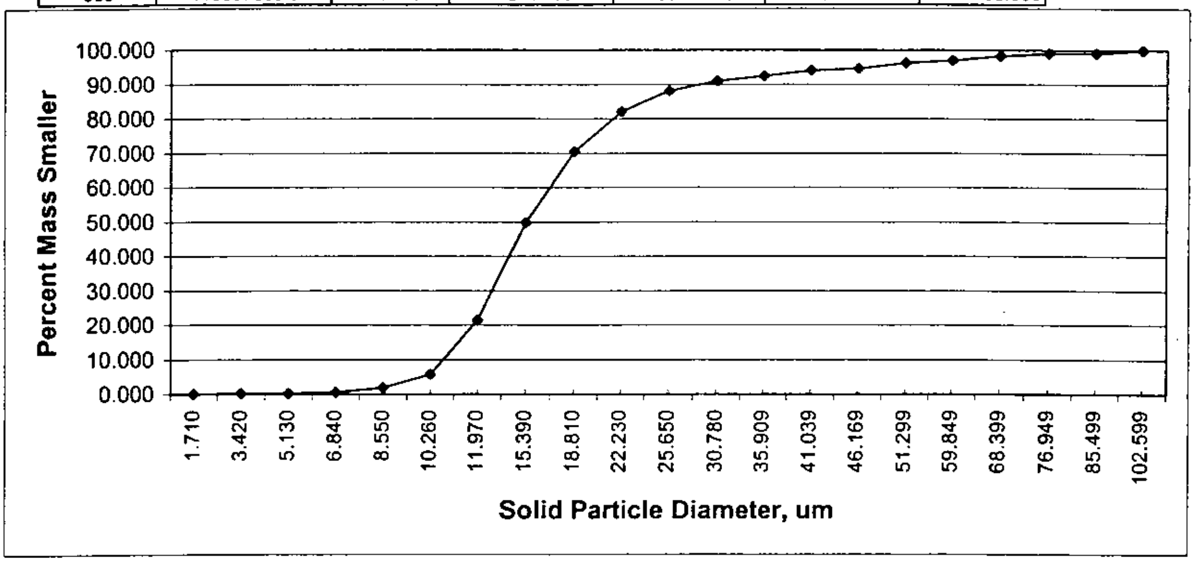
Resultant Solid Particulate Size Destribution (TDS = 10000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.24E-06	2.38	1.657	0.000
20	4188.8	4.19E-03	4.19E-05	19.04	3.313	0.196
30	14137.2	1.41E-02	1.41E-04	64.26	4.970	0.226
40	33510.3	3.35E-02	3.35E-04	152.32	6.626	0.514
50	65449.8	6.54E-02	6.54E-04	297.50	8.283	1.816
60	113097.3	1.13E-01	1.13E-03	514.08	9.939	5.702
70	179594.4	1.80E-01	1.80E-03	816.34	11.596	21.348
90	381703.5	3.82E-01	3.82E-03	1735.02	14.909	49.812
110	696910.0	6.97E-01	6.97E-03	3167.77	18.222	70.509
130	1150346.5	1.15E+00	1.15E-02	5228.85	21.535	82.023
150	1767145.9	1.77E+00	1.77E-02	8032.48	24.848	88.012
180	3053628.1	3.05E+00	3.05E-02	13880.13	29.817	91.032
210	4849048.3	4.85E+00	4.85E-02	22041.13	34.787	92.468
240	7238229.5	7.24E+00	7.24E-02	32901.04	39.756	94.091
270	10305994.7	1.03E+01	1.03E-01	46845.43	44.726	94.689
300	14137166.9	1.41E+01	1.41E-01	64259.85	49.695	96.288
350	22449297.5	2.24E+01	2.24E-01	102042.26	57.978	97.011
400	33510321.6	3.35E+01	3.35E-01	152319.64	66.260	98.340
450	47712938.4	4.77E+01	4.77E-01	216876.99	74.543	99.071
500	65449846.9	6.54E+01	6.54E-01	297499.30	82.825	99.071
600	113097335.5	1.13E+02	1.13E+00	514078.80	99.390	100.000



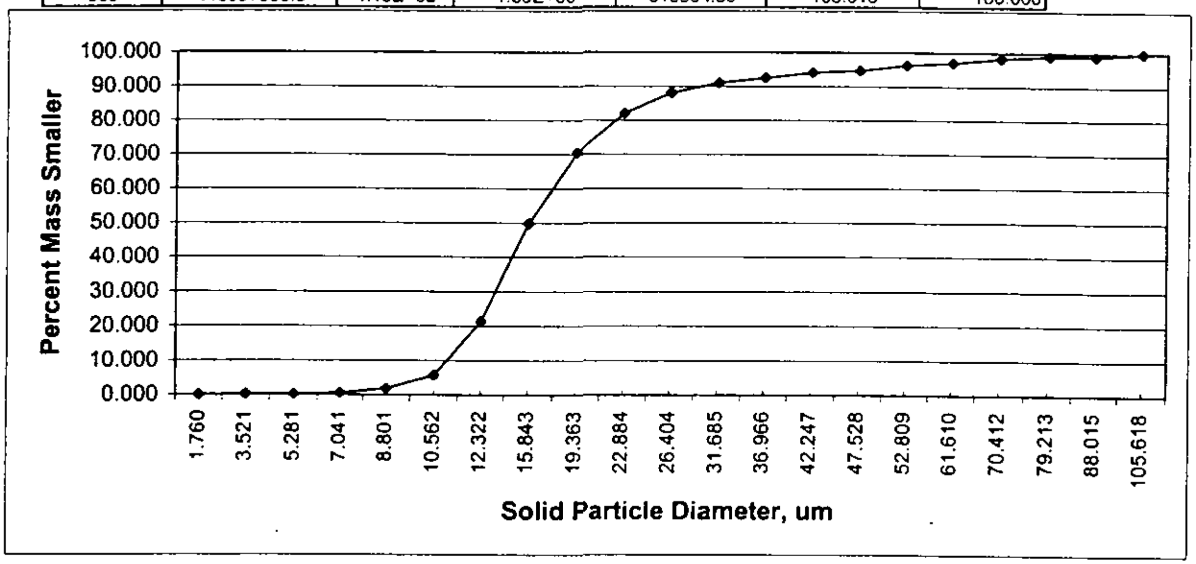
Resultant Solid Particulate Size Destribution (TDS = 11000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.76E-06	2.62	1.710	0.000
20	4188.8	4.19E-03	4.61E-05	20.94	3.420	0.196
30	14137.2	1.41E-02	1.56E-04	70.69	5.130	0.226
40	33510.3	3.35E-02	3.69E-04	167.55	6.840	0.514
50	65449.8	6.54E-02	7.20E-04	327.25	8.550	1.816
60	113097.3	1.13E-01	1.24E-03	565.49	10.260	5.702
70	179594.4	1.80E-01	1.98E-03	897.97	11.970	21.348
90	381703.5	3.82E-01	4.20E-03	1908.52	15.390	49.812
110	696910.0	6.97E-01	7.67E-03	3484.55	18.810	70.509
130	1150346.5	1.15E+00	1.27E-02	5751.73	22.230	82.023
150	1767145.9	1.77E+00	1.94E-02	8835.73	25.650	88.012
180	3053628.1	3.05E+00	3.36E-02	15268.14	30.780	91.032
210	4849048.3	4.85E+00	5.33E-02	24245.24	35.909	92.468
240	7238229.5	7.24E+00	7.96E-02	36191.15	41.039	94.091
270	10305994.7	1.03E+01	1.13E-01	51529.97	46.169	94.689
300	14137166.9	1.41E+01	1.56E-01	70685.83	51.299	96.288
350	22449297.5	2.24E+01	2.47E-01	112246.49	59.849	97.011
400	33510321.6	3.35E+01	3.69E-01	167551.61	68.399	98.340
450	47712938.4	4.77E+01	5.25E-01	238564.69	76.949	99.071
500	65449846.9	6.54E+01	7.20E-01	327249.23	85.499	99.071
600	113097335.5	1.13E+02	1.24E+00	565486.68	102.599	100.000



Resultant Solid Particulate Size Destribution (TDS = 12000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	6.28E-06	2.86	1.760	0.000
20	4188.8	4.19E-03	5.03E-05	22.85	3.521	0.196
30	14137.2	1.41E-02	1.70E-04	77.11	5.281	0.226
40	33510.3	3.35E-02	4.02E-04	182.78	7.041	0.514
50	65449.8	6.54E-02	7.85E-04	357.00	8.801	1.816
60	113097.3	1.13E-01	1.36E-03	616.89	10.562	5.702
70	179594.4	1.80E-01	2.16E-03	979.61	12.322	21.348
90	381703.5	3.82E-01	4.58E-03	2082.02	15.843	49.812
110	696910.0	6.97E-01	8.36E-03	3801.33	19.363	70.509
130	1150346.5	1.15E+00	1.38E-02	6274.62	22.884	82.023
150	1767145.9	1.77E+00	2.12E-02	9638.98	26.404	88.012
180	3053628.1	3.05E+00	3.66E-02	16656.15	31.685	91.032
210	4849048.3	4.85E+00	5.82E-02	26449.35	36.966	92.468
240	7238229.5	7.24E+00	8.69E-02	39481.25	42.247	94.091
270	10305994.7	1.03E+01	1.24E-01	56214.52	47.528	94.689
300	14137166.9	1.41E+01	1.70E-01	77111.82	52.809	96.288
350	22449297.5	2.24E+01	2.69E-01	122450.71	61.610	97.011
400	33510321.6	3.35E+01	4.02E-01	182783.57	70.412	98.340
450	47712938.4	4.77E+01	5.73E-01	260252.39	79.213	99.071
500	65449846.9	6.54E+01	7.85E-01	356999.17	88.015	99.071
600	113097335.5	1.13E+02	1.36E+00	616894.56	105.618	100.000



Calculating Realistic PM_{10} Emissions from Cooling Towers

Abstract No. 216 Session No. AM-1b

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ABSTRACT

Particulate matter less than 10 micrometers in diameter (PM_{10}) emissions from wet cooling towers may be calculated using the methodology presented in EPA's AP-42[1], which assumes that all total dissolved solids (TDS) emitted in "drift" particles (liquid water entrained in the air stream and carried out of the tower through the induced draft fan stack.) are PM_{10}. However, for wet cooling towers with medium to high TDS levels, this method is overly conservative, and predicts significantly higher PM_{10} emissions than would actually occur, even for towers equipped with very high efficiency drift eliminators (e.g., 0.0006% drift rate). Such over-prediction may result in unrealistically high PM_{10} modeled concentrations and/or the need to purchase expensive Emission Reduction Credits (ERCs) in PM_{10} non-attainment areas. Since these towers have fairly low emission points (10 to 15 m above ground), over-predicting PM_{10} emission rates can easily result in exceeding federal Prevention of Significant Deterioration (PSD) significance levels at a project's fenceline. This paper presents a method for computing realistic PM_{10} emissions from cooling towers with medium to high TDS levels.

INTRODUCTION

Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. Wet, or evaporative, cooling towers rely on the latent heat of water evaporation to exchange heat between the process and the air passing through the cooling tower. The cooling water may be an integral part of the process or may provide cooling via heat exchangers, for example, steam condensers. Wet cooling towers provide direct contact between the cooling water and air passing through the tower, and as part of normal operation, a very small amount of the circulating water may be entrained in the air stream and be carried out of the tower as "drift" droplets. Because the drift droplets contain the same chemical impurities as the water circulating through the tower, the particulate matter constituent of the drift droplets may be classified as an emission. The magnitude of the drift loss is influenced by the number and size of droplets produced within the tower, which are determined by the tower fill design, tower design, the air and water patterns, and design of the drift eliminators.

AP-42 METHOD OF CALCULATING DRIFT PARTICULATE

EPA's AP-42[1] provides available particulate emission factors for wet cooling towers, however, these values only have an emission factor rating of "E" (the lowest level of confidence acceptable). They are also rather high, compared to typical present-day manufacturers' guaranteed drift rates, which are on the order of 0.0006%. (Drift emissions are typically expressed as a percentage of the cooling tower water circulation rate). AP-42 states that "a *conservatively high* PM_{10} emission factor can be obtained by (a) multiplying the total liquid drift factor by the TDS fraction in the circulating water, and (b) assuming that once the water evaporates, all remaining solid particles are within the PM_{10} range." (Italics per EPA).

If TDS data for the cooling tower are not available, a source-specific TDS content can be estimated by obtaining the TDS for the make-up water and multiplying it by the cooling tower cycles of concentration. [The cycles of concentration is the ratio of a measured parameter for the cooling tower water (such as conductivity, calcium, chlorides, or phosphate) to that parameter for the make-up water.]

Using AP-42 guidance, the total particulate emissions (PM) (after the pure water has evaporated) can be expressed as:

$$PM = \text{Water Circulation Rate} \times \text{Drift Rate} \times \text{TDS} \qquad [1]$$

For example, for a typical power plant wet cooling tower with a water circulation rate of 146,000 gallons per minute (gpm), drift rate of 0.0006%, and TDS of 7,700 parts per million by weight (ppmw):

$$PM = 146{,}000 \text{ gpm} \times 8.34 \text{ lb water/gal} \times 0.0006/100 \times 7{,}700 \text{ lb solids}/10^6 \text{ lb water} \times 60 \text{ min/hr} = \underline{3.38 \text{ lb/hr}}$$

On an annual basis, this is equivalent to almost 15 tons per year (tpy). Even for a state-of-the-art drift eliminator system, this is not a small number, especially if assumed to all be equal to PM_{10}, a regulated criteria pollutant. However, as the following analysis demonstrates, only a very small fraction is actually PM_{10}.

COMPUTING THE PM_{10} FRACTION

Based on a representative drift droplet size distribution and TDS in the water, the amount of solid mass in each drop size can be calculated. That is, for a given initial droplet size, assuming that the mass of dissolved solids condenses to a spherical particle after all the water evaporates, and assuming the density of the TDS is equivalent to a representative salt (e.g., sodium chloride), the diameter of the final solid particle can be calculated. Thus, using the drift droplet size distribution, the percentage of drift mass containing particles small enough to produce PM_{10} can be calculated. This method is conservative as the final particle is assumed to be perfectly spherical; hence as small a particle as can exist.

The droplet size distribution of the drift emitted from the tower is critical to performing the analysis. Brentwood Industries, a drift eliminator manufacturer, was contacted and agreed to provide drift eliminator test data from a test conducted by Environmental Systems Corporation (ESC) at the Electric Power Research Institute (EPRI) test facility in Houston, Texas in 1988 (Aull[2], 1999). The data consist of water droplet size distributions for a drift eliminator that achieved a tested drift rate of 0.0003 percent. As we are using a 0.0006 percent drift rate, it is reasonable to expect that the 0.0003 percent drift rate would produce smaller droplets, therefore, this size distribution data can be assumed to be <u>conservative</u> for predicting the fraction of PM_{10} in the total cooling tower PM emissions..

In calculating PM_{10} emissions the following assumptions were made:

- Each water droplet was assumed to evaporate shortly after being emitted into ambient air, into a single, solid, spherical particle.
- Drift water droplets have a density (ρ_w) of water; 1.0 g/cm^3 or $1.0*10^{-6}\ \mu g/\mu m^3$.
- The solid particles were assumed to have the same density (ρ_{TDS}) as sodium chloride, (i.e., 2.2 g/cm^3).

Using the formula for the volume of a sphere, $V = 4\pi r^3/3$, and the density of pure water, $\rho_w = 1.0$ g/cm^3, the following equations can be used to derive the solid particulate diameter, D_p, as a function of the TDS, the density of the solids, and the initial drift droplet diameter, D_d :

$$\text{Volume of drift droplet} = (4/3)\pi(D_d/2)^3 \qquad [2]$$

$$\text{Mass of solids in drift droplet} = (TDS)(\rho_w)(\text{Volume of drift droplet}) \qquad [3]$$

substituting,

$$\text{Mass of solids in drift} = (TDS)(\rho_w)(4/3)\pi(D_d/2)^3 \qquad [4]$$

Assuming the solids remain and coalesce after the water evaporates, the mass of solids can also be expressed as:

$$\text{Mass of solids} = (\rho_{TDS})\ (\text{solid particle volume}) = (\rho_{TDS})(4/3)\pi(D_p/2)^3 \qquad [5]$$

Equations [4] and [5] are equivalent:

$$(\rho_{TDS})(4/3)\pi(D_p/2)^3 = (TDS)(\rho_w)(4/3)\pi(D_d/2)^3 \qquad [6]$$

Solving for D_p:

$$D_p = D_d\ [(TDS)(\rho_w/\rho_{TDS})]^{1/3} \qquad [7]$$

Where,

TDS is in units of ppmw
D_p = diameter of solid particle, micrometers (μm)
D_d = diameter of drift droplet, μm

Using formulas [2] – [7] and the particle size distribution test data, Table 1 can be constructed for drift from a wet cooling tower having the same characteristics as our example; 7,700 ppmw TDS and a 0.0006% drift rate. The first and last columns of this table are the particle size distribution derived from test results provided by Brentwood Industries. Using straight-line interpolation for a solid particle size 10 μm in diameter, we conclude that approximately <u>14.9 percent</u> of the mass emissions are equal to or smaller than PM_{10}. The balance of the solid particulate are particulate greater than 10 μm. Hence, PM_{10} emissions from this tower would be equal to PM emissions x 0.149, or 3.38 lb/hr x 0.149 = 0.50 lb/hr. The process is repeated in Table 2, with all parameters equal except that the TDS is 11,000 ppmw. The result is that approximately 5.11 percent are smaller at 11,000 ppm. Thus, while total PM emissions are larger by virtue of a higher TDS, overall PM_{10} emissions are actually lower, because more of the solid particles are larger than 10 μm.

Table 1. Resultant Solid Particulate Size Distribution (TDS = 7700 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2][1]	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	4.03E-06	1.83	1.518	0.000
20	4189	4.19E-03	3.23E-05	14.66	3.037	0.196
30	14137	1.41E-02	1.09E-04	49.48	4.555	0.226
40	33510	3.35E-02	2.58E-04	117.29	6.073	0.514
50	65450	6.54E-02	5.04E-04	229.07	7.591	1.816
60	113097	1.13E-01	8.71E-04	395.84	9.110	5.702
70	179594	1.80E-01	1.38E-03	628.58	10.628	21.348
90	381704	3.82E-01	2.94E-03	1335.96	13.665	49.812
110	696910	6.97E-01	5.37E-03	2439.18	16.701	70.509
130	1150347	1.15E+00	8.86E-03	4026.21	19.738	82.023
150	1767146	1.77E+00	1.36E-02	6185.01	22.774	88.012
180	3053628	3.05E+00	2.35E-02	10687.70	27.329	91.032
210	4849048	4.85E+00	3.73E-02	16971.67	31.884	92.468
240	7238229	7.24E+00	5.57E-02	25333.80	36.439	94.091
270	10305995	1.03E+01	7.94E-02	36070.98	40.994	94.689
300	14137167	1.41E+01	1.09E-01	49480.08	45.549	96.288
350	22449298	2.24E+01	1.73E-01	78572.54	53.140	97.011
400	33510322	3.35E+01	2.58E-01	117286.13	60.732	98.340
450	47712938	4.77E+01	3.67E-01	166995.28	68.323	99.071
500	65449847	6.54E+01	5.04E-01	229074.46	75.915	99.071
600	113097336	1.13E+02	8.71E-01	395840.67	91.098	100.000

[1] Bracketed numbers refer to equation number in text.

The percentage of PM_{10}/PM was calculated for cooling tower TDS values from 1000 to 12000 ppmw and the results are plotted in Figure 1. Using these data, Figure 2 presents predicted PM_{10} emission rates for the 146,000 gpm example tower. As shown in this figure, the PM emission rate increases in a straight line as TDS increases, however, the PM_{10} emission rate increases to a maximum at around a TDS of 4000 ppmw, and then begins to decline. The reason is that at higher TDS, the drift droplets contain more solids and therefore, upon evaporation, result in larger solid particles for any given initial droplet size.

CONCLUSION

The emission factors and methodology given in EPA's AP-42[1] Chapter 13.4 *Wet Cooling Towers*, do not account for the droplet size distribution of the drift exiting the tower. This is a critical factor, as more than 85% of the mass of particulate in the drift from most cooling towers will result in solid particles larger than PM_{10} once the water has evaporated. Particles larger than PM_{10} are no longer a regulated air pollutant, because their impact on human health has been shown to be insignificant. Using reasonable, conservative assumptions and a realistic drift droplet size distribution, a method is now available for calculating realistic PM_{10} emission rates from wet mechanical draft cooling towers equipped with modern, high-efficiency drift eliminators and operating at medium to high levels of TDS in the circulating water.

Table 2. Resultant Solid Particulate Size Distribution (TDS = 11000 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2][1]	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	5.76E-06	2.62	1.710	0.000
20	4189	4.19E-03	4.61E-05	20.94	3.420	0.196
30	14137	1.41E-02	1.56E-04	70.69	5.130	0.226
40	33510	3.35E-02	3.69E-04	167.55	6.840	0.514
50	65450	6.54E-02	7.20E-04	327.25	8.550	1.816
60	113097	1.13E-01	1.24E-03	565.49	10.260	5.702
70	179594	1.80E-01	1.98E-03	897.97	11.970	21.348
90	381704	3.82E-01	4.20E-03	1908.52	15.390	49.812
110	696910	6.97E-01	7.67E-03	3484.55	18.810	70.509
130	1150347	1.15E+00	1.27E-02	5751.73	22.230	82.023
150	1767146	1.77E+00	1.94E-02	8835.73	25.650	88.012
180	3053628	3.05E+00	3.36E-02	15268.14	30.780	91.032
210	4849048	4.85E+00	5.33E-02	24245.24	35.909	92.468
240	7238229	7.24E+00	7.96E-02	36191.15	41.039	94.091
270	10305995	1.03E+01	1.13E-01	51529.97	46.169	94.689
300	14137167	1.41E+01	1.56E-01	70685.83	51.299	96.288
350	22449298	2.24E+01	2.47E-01	112246.49	59.849	97.011
400	33510322	3.35E+01	3.69E-01	167551.61	68.399	98.340
450	47712938	4.77E+01	5.25E-01	238564.69	76.949	99.071
500	65449847	6.54E+01	7.20E-01	327249.23	85.499	99.071
600	113097336	1.13E+02	1.24E+00	565486.68	102.599	100.000

Figure 1: Percentage of Drift PM that Evaporates to PM10

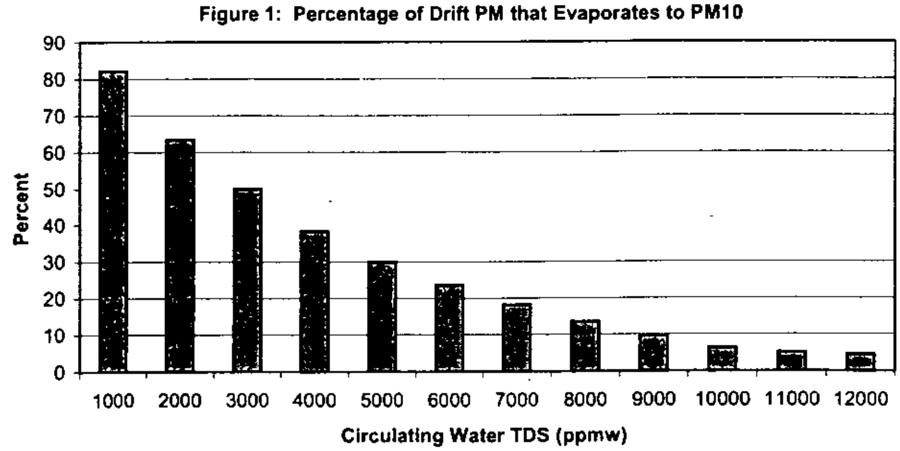
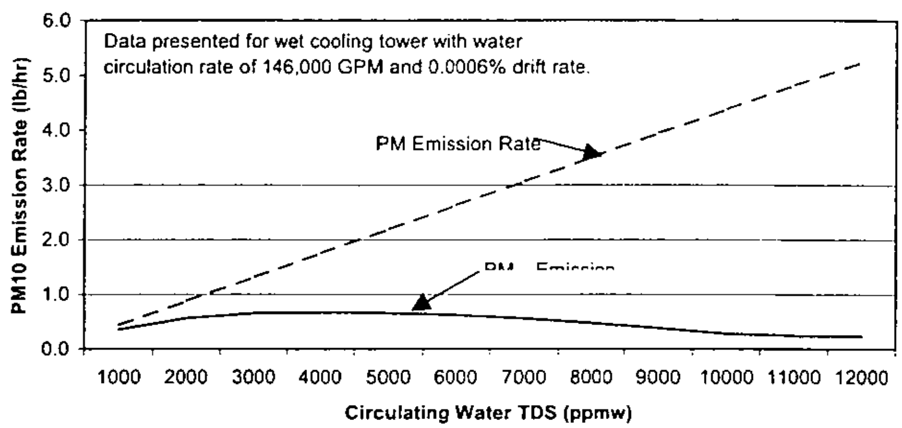


Figure 2: PM_{10} Emission Rate vs. TDS



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2. Aull, 1999. Memorandum from R. Aull, Brentwood Industries to J. Reisman, Greystone, December 7, 1999.

KEY WORDS

Drift
Drift eliminators
Cooling tower
PM_{10} emissions
TDS

APPENDIX B

BEST AVAILABLE CONTROL TECHNOLOGY FOR THE PROPOSED COMBUSTION TURBINES

B.1 NEW SOURCE PERFORMANCE STANDARDS

BACT is a case-by-case emission limitation for each applicable pollutant, based on the maximum degree of emission reduction after taking into account the energy, environmental, and economic impacts, and other costs. The BACT cannot be any less stringent than any applicable new source performance standards (NSPS) and consideration must be given to the applicable NSPS in the determination of BACT. This requirement also applies for any applicable National Emission Standard for Hazardous Air Pollutants promulgated under 40 CFR Part 61. For combustion turbines the applicable NSPS is 40 CFR Part 60, Subpart GG Standards of Performance for Stationary Gas Turbines.

B.1.1 SUBPART GG

The NSPS regulations (40 CFR, Subpart GG) applicable to gas turbines apply to:

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100×10^6 Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and 100×10^6 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 combustion turbines proposed for the project and are the most stringent provision of the NSPS. These requirements are summarized in Table B-1 and were considered in the BACT analysis.

As noted from Table B-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 0.03 percent, the NSPS is increased by 0.0012 percent or 12 parts per million (ppm). The NSPS NO_x emission limit adjustment is not affected by natural gas combustion.

B.1.2 SUBPART DA

On September 16, 1998, the NSPS for fossil fuel fired steam electric generators with more than 250 MMBtu/hr heat input were updated to include generally more stringent emission limitations for NO_x. These revised NSPS (Subpart Da) apply to any affected facility, which commenced construction after July 9, 1997. The applicable NO_x NSPS limit for firing coal, oil or natural gas, or a mixture of these, or any other fuels, is 1.6 lb/MW [40 CFR 60.44a(d)(1)]. These NSPS are applicable to the project.

B.2 BEST AVAILABLE CONTROL TECHNOLOGY

The "top-down" analysis for determining BACT, as provided for in EPA's Draft 1990 New Source Review Workshop Manual was considered in evaluating BACT for the Project. The procedure involves 5 steps: identification of control technologies, elimination of technically infeasible control technologies, a ranking of the control technologies, an evaluation of the effective control technologies and the selection of BACT.

The identification of control technologies is developed from the information obtained from BACT/LAER Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina. While these data are comprehensive it is often not up to date with the most recent BACT/LAER decisions and separate contact with state agencies is required. 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).

The elimination of infeasible technologies is based on those engineering aspects that would preclude a technology's use due to physical, chemical or other engineering consideration. Control technologies that are technically feasible are ranked by control effectiveness, with determination of the environmental, economic and energy costs and benefits of the control technologies. This information forms the basis for the case-by-case consideration of environmental, energy and economic impacts. The "top" feasible control alterable is selected unless it can be rejected based on economic, environmental or energy considerations. This section of Appendix B presents information related to the proposed BACT emission limitation.

B.2.1 NITROGEN OXIDES

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 B-2 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 including duct firing. This table was developed from the information obtained from BACT/LAER Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina.

Historically, the most stringent NO_x controls for CTs established as LAER/BACT by state agencies were combustion controls with selective catalytic reduction (SCR) and combustion controls alone. SCR is a post-combustion control, while advanced dry low-NO_x combustors minimize the formation of NO_x in the combustion process. When SCR has been employed, dry low-NO_x combustion technology is used to minimize the NO_x emissions formed in the combustion process.

Wet injection was the first combustion technology introduced for combustion turbines (pre-1980's) and was the primary method of reducing NO_x emissions from CTs prior to the 1990's. Indeed, 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. Wet injection is still the only means of reducing NO_x formation in the combustion process when firing oil.

The dry low-NO_x combustion technology has been developed and made available since the early 1990's for gas turbines to achieve emission levels of 25 ppmvd corrected to 15 percent O_2. More recently, however, CT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 9 ppmvd (corrected to 15 percent O_2) when firing natural gas.

SCR is an available and demonstrated control technology for NO_x control or combined cycle units, which has been installed or permitted in over 100 projects. Beginning in the late 1980s and early 1990s, SCR was initially installed on cogeneration facilities with capacities of 50 MW or less. Most of these projects were in California. Many of these initial SCR projects were located in the Southern California NO_2 nonattainment area where SCR was required not as BACT but as LAER, a more stringent requirement. As noted previously, there are distinct regulatory and policy differences between LAER and BACT. As discussed in Section 3.0, BACT involves an evaluation of the economic, environmental, and energy impacts of alternative control technologies. In contrast, LAER only considers the technical aspects of control.

More recently, projects with SCR have been installed throughout the US. A majority of these projects are natural gas-fired combined cycle facilities. The size of these projects ranges from 22 MW to over 500 MW. While many 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 over 80 percent of NO_x in the exhaust gas stream. The most common BACT emission limiting standard over the last two years is 3.5 ppmvd corrected to 15 percent O_2 or less for natural gas firing when using DLN and SCR. The most common emission limiting standard established as LAER is 2.5 ppmvd corrected to 15 percent O_2 or less for natural gas firing and using SCR.

Other available control technologies that have become available for controlling NO_x emissions from combustion turbines for include SCONO$_x$™ and XONON™. SCONO$_x$™ is an add-on control using absorption and chemical conversion to remove NO_x formed from combustion, while XONON™ is a catalytic combustion system integral to the turbine. Other potential technologies used in combustion process for NO_x removal include: NO$_x$OUT, Thermal DeNO$_x$, and NSCR.

Technology Descriptions and Feasibility

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 results (i.e., CO and VOC emissions). In "F" Class turbines using wet injection with gas firing, the NO_x emission rates in the range of 30 ppm have been demonstrated. However, wet injection is no longer offered for gas firing in "F" Class turbines. Wet injection is the only current feasible means of reducing NO_x emissions in the combustion process when firing oil.

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 conventional machines manufactured by General Electric (GE), Siemens Westinghouse, Mitsubishi Heavy Industries (MHI) and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. All these vendors have offered dry low-NO_x combustors on advanced heavy-duty industrial machines. 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 when firing natural gas at baseload conditions is 9 ppmvd (corrected to 15 percent O_2), a level which is guaranteed by the selected vendor for the project.

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (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. Exhaust gas temperatures of simple cycle CTs generally are in the range of 1,000°F, which exceeds the optimum range for SCR with base metal catalysts. 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 primarily limited to combined-cycle facilities that burn natural gas with small amounts of fuel oil. Initially, the traditional metal catalysts used in SCR systems were contaminated by sulfur-containing fuels. For most fuel-oil-burning facilities, catalyst operation was discontinued, or the exhaust bypasses the SCR system. This was due to the formation of ammonium salts (ammonium sulfate and bisulfate) resulting from 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 with concomitant cost and technical requirements. 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. Ceramic and specially designed catalysts have been designed to overcome the problems with base-metal catalysts. The sulfur in No. 2 distillate oil has also been reduced from 0.5 percent available in the early 1990's to 0.05 percent. In addition, HRSG designs can accommodate the impacts of the formation of ammonium salts.

For combined cycle units, SCR is an available, technically feasible and demonstrated technology.

SCONO$_x$™ Process

SCONO$_x$™ is a NO_x and CO control system exclusively offered by Goal Line Environmental Technologies (GLET). GLET is a partnership formed by Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc. In 1998, ABB acquired the exclusive license for the technology in the United States for control applications larger than 100 MW.

The SCONO$_x$™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The SCONO$_x$™ oxidation/absorption cycle reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (1)$$

$$NO + \frac{1}{2} O_2 \rightarrow NO_2 \quad (2)$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \qquad (3)$$

CO_2 produced by reaction (1) and (2) is released to the atmosphere as part of the CT/HRSG exhaust gas stream.

As shown in Reaction (3), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The SCONO$_x$™ regeneration cycle reaction is:

$$KNO_2 + KNO_3 + 4\ H_2 + CO_2 \rightarrow K_2CO_3 + 4\ H_2O_{(g)}) + N_2 \qquad (4)$$

Water vapor and elemental nitrogen are released to the atmosphere as part of the CT/HRSG exhaust stream. Following regeneration, the SCONO$_x$™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being regenerated. At any given time, 75 percent of the catalyst sections will be in the oxidation/absorption cycle, while 25 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 5 minutes.

Regeneration gas is produced by reacting natural gas with O_2 present in ambient air. The SCONO$_x$™ system uses a gas generator produced by Surface Combustion. This unit uses a two-stage process to produce hydrogen and carbon dioxide. In the first stage, natural gas and ambient air are reacted across a partial oxidation catalyst at 1,900°F to form CO and hydrogen. Steam is added and the gas mixture is then passed across a low temperature shift catalyst, forming CO_2 and additional hydrogen. The resulting gas stream is diluted to less than 4 percent hydrogen using steam or another inert gas. The regeneration gas reactions are:

$$CH_4 + \frac{1}{2} O_2 + 1.88\ N_2 \rightarrow CO + 2\ H_2 + 1.88\ N_2 \quad (5)$$

$$CO + 2\ H_2 + H_2O + 1.88\ NO_2 \rightarrow CO_2 + 3\ H_2 + 1.88\ N_2 \quad (6)$$

The SCONO$_x$™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For SCONO$_x$™ systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the SCONO$_x$™ catalyst that reforms the natural gas.

The SCONO$_x$™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system (SCOSO$_x$™) to remove sulfur compounds is installed upstream of the SCONO$_x$™ catalyst. During regeneration of the SCONO$_x$™ catalyst, either hydrogen sulfide or SO_2 is released to the atmosphere as part of the CT/HRSG exhaust gas stream. The absorption portion of the SCOSO$_x$™ process is proprietary. SCOSO$_x$™ oxidation/absorption and regeneration reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (7)$$

$$SO_2 + \frac{1}{2} O_2 \rightarrow SO_3 \quad (8)$$

$$SO_3 + SORBER \rightarrow [SO_3 + SORBER] \quad (9)$$

$$[SO_3 + SORBER] + 4\ H_2 \rightarrow H_2S + 3\ H_2O \quad (10)$$

Utility materials needed for the operation of the SCONO$_x$™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the SCONO$_x$™ control system is limited to one small combined cycle (CC) power plant located in Los Angeles. This power plant, owned by GLET partner Sunlaw Energy Corporation, utilizes a GE LM2500 turbine (30 MW size) equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The SCONO$_x$™ control system was installed at the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 ppmv resulting in an approximate 85 percent NO_x removal efficiency.

A second $SCONO_x$™ system was installed at the Genetics Institute Facility in Andover, Massachusetts in late 1998. The system is installed on a 5-MW Caterpillar Solar Turbine with a Deltak boiler. The NO_x emission limit is 2.5 ppmvd at 15-percent O_2. ABB Environmental reports that the system is operating successfully, although there have been incidents of high NO_x emissions that ABB Environmental attributes to combustion control problems and not to the $SCONO_x$™ system.

XONON™ Catalytic Combustor

Catalytic combustors are being developed for low emission applications on turbines where the catalyst is internal to the combustion system. The XONON™ Combustion System is a catalytic combustion system developed by Catalytica Combustion Systems, Inc. that can achieve low emission levels of NO_x, CO and VOCs. The XONON" system combusts the fuel over a catalyst, reducing the temperature of combustion and providing for more complete combustion of the fuel. The system is referred to as "flameless combustion" where temperature are below those where limited NO_x formation occurs. However, the exhaust temperatures from a combustion turbine standpoint are still sufficient for the expansion of the gases through the turbine for power generation. Emission levels of NO_x at less than 2 ppm have been reported for the 1.5 MW Kawasaki gas turbine located at Sun Valley Power. Recently, this technology has been proposed for a 750 MW combined cycle facility. This facility, the Pastoria Energy Facility, is a project proposed by affiliates of Enron Corporation, which has a 15 percent interest in Catalytica Combustion Systems, Inc. Commercial operation is scheduled for the summer of 2003. Catalytica is currently working in collaboration with several gas turbine manufacturers including General Electric, Pratt & Whitney, Rolls Royce Allison and Solar.

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:

$$CO(NH_2)_2 + 2NO + \frac{1}{2} O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

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 and 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 "F" Class CT is about 1,100°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

Thermal DeNO$_x$

Thermal DeNO$_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal DeNO$_x$ requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream 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 material requirements, 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 an "F" Class combustion turbine is typically 1,100°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

Nonselective Catalytic Reduction

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

Technology Demonstration and Feasibility

The combustion controls using dry low-NO_x combustors for the combustion turbine and low-NO_x burners for duct firing are available, demonstrated and technically feasible for combustion turbines in either simple cycle or combined cycle configuration. The dry low-NO_x combustion technology alone can achieve 9 ppm (corrected to 15 percent O_2 dry conditions) when firing natural gas.

The technical evaluation of post-combustion gas controls that include NO_xOUT, Thermal $DeNO_x$, and NSCR, and indicate that these processes have not been applied to either simple cycle combustion turbines or combined cycle systems and are technically infeasible for the project because of process constraints (e.g., temperature). The $SCONO_x$™ control technology is available but not considered to be technically feasible because it has not been commercially demonstrated on large "F" Class CTs. The CTs planned for the project, General Electric Frame 7FA units, each have a nominal generating capacity of 170 MW which are approximately seven times larger than the nominal 25-MW GE LM2500 utilized at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the $SCONO_x$™ technology given the large differences in machine flow rates are unknown. Additional concerns with the $SCONO_x$™ control technology include process complexity (multiple catalytic oxidation/absorption/regeneration systems), reliance on only one supplier, relatively brief operating history of the technology, and distillate oil firing. While the XONON® catalytic combustion system is applied directly to the combustion turbine, application on a large combined cycle unit has not been demonstrated. For these reasons, the $SCONO_x$™ and XONON® are still considered in the commercial demonstration stage. SCR is commercially available, technically feasible and demonstrated for combined cycle units.

For combined cycle operation, the combination of dry low-NO_x combustion technology and water injection with SCR is a technically feasible alternative that can achieve a maximum degree of emission reduction. The combined technology is capable of achieving a NO_x emission levels of 3.5 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions) 12 ppm when firing distillate oil (corrected to 15 percent O_2 dry conditions).

Below is a summary of the technical availability, demonstration and feasibility for the proposed project.

Combined Cycle

Technology	Status
Selective Catalytic Reduction	Available, Demonstrated and Feasible
Dry Low-NO_x Combustors	Available, Demonstrated and Feasible for gas firing
Wet Injection	Available, Demonstrated or Feasible for oil firing
$SCONO_x$	Available, Not Demonstrated
XOXON™	Not Demonstrated
Thermal De NO_x	Not Available or Feasible
NO_x Out	Not Available or Feasible
NSCR	Not Available or Feasible

SCR Cost Estimates

Tables B-3 and B-4 present the total capital and annualized cost to achieve 3.5 ppmvd corrected to 15 percent oxygen when firing natural gas using SCR and $SCONO_x$™ applied to combined cycle operation, respectively. The emission rate for oil firing for both SCR and $SCONO_x$™ is based on 12 ppmvd corrected to 15 percent oxygen. The costs were developed using EPA Cost Control Manual (EPA, 1990 & 1993) and vendor based estimates for each control system. Standard EPA recommended cost factors were used. A capital recovery period of 15 years was used for the capital costs. Tables B-3a and B-4a present the total capital and annualized cost to achieve 2.5 ppmvd corrected to 15 percent oxygen.

Comparison of Economic, Environmental, and Energy Impacts

Tables B-5 present a comparison of the economic, environmental, and energy impacts associated with the top control alternatives to achieve 3.5 ppmvd corrected to 15 percent oxygen when firing gas and 12 ppmvd corrected to 15 percent oxygen when firing oil. Table B-6 presents the potential emissions resulting from the formation of ammonium salts (i.e., particulate matter), ammonia slip and secondary emissions. Tables B-5a and B-6a present the economic, environmental and energy impacts associated with achieving 2.5 ppmvd corrected to 15 percent oxygen when firing natural gas.

B.2.2 CARBON MONOXIDE

Identification of CO Control Technologies

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 B-7 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.

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

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 an efficiency of 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.

Oxidation Catalyst Costs

Tables B-8 and B-9 present the capital and annualized cost for an oxidation catalyst installed in the HRSG.

Comparison of Economic, Environmental, and Energy Impacts

Table B-10 presents a comparison of the economic, environmental, and energy impacts associated with the top control alternatives for the combined cycle unit. Table B-11 presents the potential emissions resulting from the formation of ammonium salts (i.e., particulate matter), ammonia slip and secondary emissions. The latter results from generation lost due to the back pressure of the oxidation catalyst. The maximum CO impacts are less than 0.5 percent of the applicable ambient air quality standards. There would also be no secondary benefits, such as reducing acidic deposition, to reducing CO.

Table B-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.

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	3.5 ppm NG; 41 ppm w/ FO	DLN/SCR;WI		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.95 ppm NG; 11.3 ppm FO	DLN/SCR; WI/SCR		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		For NO_x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.013/0.048 lb/mmbtu NG/FO - GE; 0.013/0.046 lb/mmbtu	SCR/WI		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu)	SCR - CC, DLN-SC	an/1-hr	8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.013 lb/mmBtu (30.7 lb/hr)	SCR	3-hr	
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmBtu)	SCR		
Tenaska Alabama IV Partners	AL	draft permit	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONOx - \$6,145/ton NO_x; CatOx-\$1,506/ton CO
Duke Energy Autauga, LLC	AL	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$18760/ton NO_x; CatOx-\$5,006/ton CO
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 15 ppm FO	SCR		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	9 ppm or 6 ppm	DLN or SCR		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	6 ppm NG - full load; 42 ppm FO	SCR; WI		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	82.9 lb/hr w/DB, 113.2 lb/hr w/ DB & SA	DLN	30-day	Netting out of PSD for NO_x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		Repowering. 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Netting out of PSD review for NO_x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr Block	2,800 hr/yr - Power Aug. mode

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	SCR; WI	24-hr Block	SCONOx - $16,712/ton NO_x; CatOx - $2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		SCONOx - no cost eval.; CatOx - $4,350/ton CO
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	3.5 ppm NG; 16.4 ppm FO	SCR		Repowering project: netting out of NO_x, CO, PM_{10} and SO_2 review (subject to VOC reveiw)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode.
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		base/duct burner/power aug./60-70% load; SCONOx - $9,982/ton NO_x; CatOx - $1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	draft permit	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	3.5 ppm NG; 15 ppm FO	SCR		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	3.5 ppm NG; 10 ppm FO	SCR		
Broward Energy Center	FL	draft permit	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 12 ppm FO/25 ppm NG; 42 ppm FO	SCR/DLN; WI		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	draft permit	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Repowering Project: Netting out of PSD for NO_x, SO_2, VOC, lead and SAM (subject for PM_{10} and CO)
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR	30 day	
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Buffalo Creek, LLC	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		SCONOx - $19,948/ton NO_x; CatOx - $2,469/ton CO
Augusta Energy LLC	GA	draft permit	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 42 ppm FO	SCR; WI		SCONOx - $17,490/ton NO_x; CatOx - $4,133/ton CO
GenPower McIntosh	GA	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Monroe Power Co.	GA	applic. under review	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	12/3.5 ppm	DLN/SCR		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	applic. under review	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	3.5/9 ppm	SCR/DLN;		
Duke Energy Tift	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $16,274/ton NO_x; CatOx - $2,095/ton CO
CPV Terrapin, LLC	GA	applic. under review	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 5.4 ppm (NG w/DB); 8.0 ppm FO	SCR		

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Kinder Morgan Georgia, LLC - Tift Power	GA	applic. under review	560	7	7	1 - GE 7EA & 6 - LM6000	NG	CC	8,760; 3,760 (part load)	9 ppm & 22 ppm	DLN & WI	annual	
Hartwell Development Co.	GA	applic. under review	564	2	0	GE 7FA (176 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $35,422/ton NO_x; CatOx - $4,964/ton CO
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/ NG	CC	8,760	15/20 ppm	Steam Injection	3-hr	
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Cogentrix Energy, Southaven Power Project	MS	draft permit	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	4.5 ppm (10.8 ppm w/ DB)	DLN/SCR		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	3.5 ppm (w/DB)	DLN/SCR		revised application to add SCR
GenPower - McAdams LLC	MS	draft permit	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr	
Lone Oak Energy Center	MS	draft permit	800	3	3	F" Class (180 MW)	NG	CC	8,760	3.5 ppm	SCR		Base/PA/PA+DF/DF
Lee Power Partners	MS	draft permit	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
LSP-Pike Energy LLC	MS	draft permit	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	4.5 ppm	SCR		
Magnolia Energy	MS	draft permit	900	3	3	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	3.5 ppm	DLN, SCR		
Reliant Energy - Choctaw Co., LLC	MS	draft permit	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN, SCR	30-day	SCONOx - $48,663/ton NO_x; CatOx - $3,550/ton CO
Crossroads Energy Center	MS	applic. under review	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $23,400/ton NO_x; CatOx - $11,039/ton CO
Choctaw Gas Generation, LLC	MS	applic. under review	700	2	2	SW 501G (250 MW)	NG	CC	8,760	3.5 ppm	SCR		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	
Granite Power Partners II (Batesville)	MS	applic. under review	300	1	1	SW 501F (230 MW)	NG	CC	8,760	3.5 ppm	SCR		
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	3.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI	24-hr	Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	draft permit	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
GenPower Earleys, LLC	NC	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $21,942/ton NO_x; CatOx - $3,246ton CO
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	45 ppm	DLN		Netted out of NO_x, SO_2 and PM_{10} PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	DLN/SCR; WI		SCONOx - no analysis; CatOx - $1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	3.5 ppm	DLN/SCR		
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	DLN		

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Memphis Generation LLC	TN	draft permit	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas). Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
Haywood Energy Center (Calpine)	TN	applic. under review	900	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	3.5 ppm NG; 42 ppm FO	DLN/SCR; WI		
TVA - Franklin	TN	applic. under review	610	2	2	GE 7FA (195 MW)		CC	8,760	3.5 ppm	SCR		

Abbreviations:
GE = General Electric
SW = Seimens Westinghouse
NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner
SC = Simple Cycle
CC = Combined Cycle
DLN = Dry-Low NO_x
WI = Water Injection
SCR = Selective Catalytic Reduction
CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

Table B-3. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA Combined Cycle Combustion Turbine
(3.5 ppmvd corrected for gas firing and 12 ppmvd corrected for oil firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$1,088,000	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$124,484	$0	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725	Vatavauk,1990
Instrumentation	$50,000	$50,000	Additional NO_x Monitor and System
Taxes	$65,280	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$54,400	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,426,669	$16,492,225	
Direct Installation Costs			
Foundation and supports	$114,134	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$199,734	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$57,067	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$28,533	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$14,267	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$14,267	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000	Engineering Estimate
Buildings	$15,000	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$448,001	$4,967,668	
Total Capital Costs (TCC)	$1,874,670	$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$142,667	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$71,333	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$142,667	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$28,533	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$14,267	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$42,800	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$492,267	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$2,366,937	$26,572,482	Sum of TCC and TInCC

Table B-4. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA in Combined Cycle Operation
(3.5 ppmvd corrected for gas firing and 12 ppmvd corrected for oil firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$18,720	$37,440	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$2,808	$5,616	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$117,422	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$22,875	$34,313	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1 5 times SCR
Catalyst Cost	$208,333	$312,500	3 years catalyst life, Based on Vendor Budget Estimate
Contingency	$11,555	$11,696	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$396,713	$401,565	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0 04/kWh times Capacity Factor, 200 kW for SCONOx
MW Loss and Heat Rate Penalty	$321,312	$642,625	0 3% output for SCR; 0 6% for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam), 90% boiler eff ; $3/mmBtu
Natural Gas for SCONOx	$0	$48,737	80 lb/hr, 0.044 lb/scf, 1,020 Btu/scf, $3/mmBtu
Total Energy Costs (TEC)	$349,344	$1,452,009	
Indirect Annual Costs			
Overhead	83,370	25,834	60% of Operating/Supervision Labor and Ammonia
Property Taxes	23,669	265,725	1% of Total Capital Costs
Insurance	23,669	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	259,890	2,917,659	10 98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$390,599	$3,474,942	
Total Annualized Costs	$1,136,656	$5,328,516	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$4,216	$19,765	per ton of NO_x Removed
	269.59	269.59	tons NOx removed /year; 3 5 ppmvd corrected to 15% oxygen

Table B-5. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN/WI Only	DLN/WI with SCR (3.5/12 ppmvd corrected)	DLN/WI with SCONOx™ (3.5/WI ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,366,937	$26,572,482
Annualized Costs	included	$1,136,656	$5,328,516
Cost Effectiveness (per ton of Nox removed)			
Total	NA	$4,216	$19,765
Environmental Impact [b]			
Total NOx (TPY)	401	131.8	131.8
NOx Reduction (TPY)	NA	-270	-270
Ammonia Emissions (TPY)	0	112	0
PM Emissions (TPY)	0	11.9	0
Secondary Emissions (TPY)	0	6.2	41.3
Net Emission Reduction (TPY)	NA	-140	-228
Addition Greenhouse Gas (as CO2; tons/year)	0	3,414	22,905
Energy Impacts [c]			
Energy Use (kWh/yr) - Total	0	5,232,523	35,108,528
Energy Use (kWh/yr) - Back Pressure	0	4,531,723	9,063,446
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	436	2,926
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	53,900	361,652
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	54	362
Energy Use (percent of combustion turbine output)	0	0.35%	2.32%

[a] See Tables B-3, B-4, and B-5 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.3 percent of 166 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-5a. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN/WI Only	DLN/WI with SCR (2.5/12 ppmvd corrected)	DLN/WI with SCONOx™ (2.5/WI ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,645,725	$26,572,482
Annualized Costs	included	$1,479,017	$5,682,303
Cost Effectiveness (per ton of Nox removed)			
Total	NA	$4,918	$18,894
Incremental from 3.5 ppm			
Environmental Impact [b]			
Total NOx (TPY)	401	100.7	100.7
NOx Reduction (TPY)	NA	301	301
Ammonia Emissions (TPY)	0	112	0
PM Emissions (TPY)	0	11.9	0
Secondary Emissions (TPY)	0	7.0	41.3
Net Emission Reduction (TPY)	NA	-170	-259
Additional Greenhouse Gas (as CO_2; tons/year)	0	3,857	22,905
Energy Impacts [c]			
Energy Use (kWh/yr)	0	5,912,282	35,108,528
Energy Use (kWh/yr) - Back Pressure	0	5,211,482	9,063,446
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	493	2,926
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	60,902	361,652
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	61	362
Energy Use (percent of combustion turbine output)	0	0.39%	2.32%

[a] See Tables B-3a, B-4a, and B-5a for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7a.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.345 percent of 166 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOx™

Pollutants	Incremental Emissions (tons/year) of SCR			Incremental Emissions (tons/year) of SCONOx™		
	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	11.92	0.20	12.12		1.31	1.31
Sulfur Dioxide		0.07	0.07		0.49	0.49
Nitrogen Oxides	-269.59	3.59	-266.00	-269.59	24.11	-245.48
Carbon Monoxide		2.16	2.16		14.47	14.47
Volatile Organic Compounds		0.14	0.14		0.95	0.95
Ammonia	111.82					
Total:	-145.85	6.16	-139.69	-269.59	41.32	-228.27
Carbon Dioxide (all energy requirements)		3,413.67	3,413.67		22,904.63	22,904.63

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	53,900	361,652 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-6a. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOx™ (2.5 ppm)

Pollutants	Incremental Emissions (tons/year) of SCR Primary	Secondary	Total	Incremental Emissions (tons/year) of SCONOx™ Primary	Secondary	Total
Particulate	11.92	0.22	12.14		1.31	1.31
Sulfur Dioxide		0.08	0.08		0.49	0.49
Nitrogen Oxides	-300.74	4.06	-296.68	-300.74	24.11	-276.63
Carbon Monoxide		2.44	2.44		14.47	14.47
Volatile Organic Compounds		0.16	0.16		0.95	0.95
Ammonia	111.82					
Total:	-177.00	6.96	-170.04	-300.74	41.32	-259.42
Carbon Dioxide (all energy requirements)		3,857.14	3,857.14		22,904.63	22,904.63

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	60,902	361,652 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.060 lb/MMBtu	GCP		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	0.040 lb/MMBtu NG; 0.058 lb/mmBtu FO	GCP		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	32.9 ppm NG; 46.7 ppm NG/FO	GCP		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	0.057 lb/MMBtu	GCP		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 19 or 22 ppm	GCP		For NO_x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.037/0.047/0.089 lb/mmbtu (base/PA/FO) - GE; 0.088/0.116/0.35 lb/mmbtu (base/PA/FO) - Mit	GCP		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	0.023/0.076 lb/mmBtu (w/PA and/or DB)	GCP		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 14 ppm (w/DB)	GCP		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.033 lb/mmBtu (77.7 lb/hr)	GCP		
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	0.035 lb/mmBtu	GCP		
Tenaska Alabama IV Partners	AL	draft permit	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760, 720 FO	0.088 lb/mmBtu NG (0.115 w/PA & DB); 0.35 lb/mmBtu FO	GCP		SCONOx - $6,145/ton NO_x; CatOx- $1,506/ton CO
Duke Energy Autauga, LLC	AL	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	15 ppm	GCP		SCONOx - $18760/ton NO_x; CatOx- $5,006/ton CO
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	12 ppm, 20 ppm w/ DB NG; 30 ppm FO	GCP		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	12 ppm	GCP		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	12 ppm NG; 20 ppm FO	GCP		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	25 ppm NG - full load; 30 ppm FO	GCP		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	16 ppm w/ DB, 23 ppm w/ DB & SA	GCP		Netting out of PSD for NO_x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	12 ppm NG; 20 ppm FO	GCP		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NO_x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP	24-hr Block	2,800 hr/yr - Power Aug. mode
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760, 1,000 FO	16 ppm NG; 30 ppm FO	GCP	24-hr Block	SCONOx - $16,712/ton NO_x; CatOx - $2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		SCONOx - no cost eval.; CatOx - $4,350/ton CO
TECO Gannon Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	7.2 ppm NG, 14.2 ppm FO	GCP		Repowering project: netting out of NO_x, CO, PM_{10} and SO_2 review (subject to VOC reveiw)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC,CC	3,390 8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		2 SC CT and 1 CC CT also capable of operating in SC mode.

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC,CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	10/15 6/38.5/50 ppm	GCP		base/duct burner/power aug./60-70% load; SCONOx - $9,982/ton NO_x; CatOx - $1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	draft permit	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	12.21/14.17 ppm	GCP		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG (15 ppm w/PA) ; 20 ppm FO	GCP		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	18.1 ppm NG (26.3 w/PA); 14.3 ppm FO	GCP		
Broward Energy Center	FL	draft permit	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA) ; 17 ppm FO (19 ppm 76-89% load, 26 ppm 50-75% load)	GCP	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 10 ppm FO/ 16 ppm NG; 50 ppm FO	GCP		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	draft permit	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (7.8 ppm)	GCP	24-hr (3-hr test)	Repowering Project: Netting out of PSD for NO_x, SO_2, VOC, lead and SAM (subject for PM_{10} and CO)
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	29.5 ppm/0.066 lb/MMBtu	GCP		
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	21.8 ppm	GCP		
Duke Energy Buffalo Creek, LLC	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	21.9 ppm	GCP		SCONOx - $19,948/ton NO_x; CatOx - $2,469/ton CO
Augusta Energy LLC	GA	draft permit	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	17.4 ppm NG; 20 ppm FO	GCP		SCONOx - $17,490/ton NO_x; CatOx - $4,133/ton CO
GenPower McIntosh	GA	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm/14 (w/DB) ppm	GCP		
Monroe Power Co.	GA	applic. under review	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	9 ppm	GCP		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	applic. under review	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	10.6 ppm (25 ppm w/DB)	GCP		
Duke Energy Tift	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	24.1 ppm	GCP		SCONOx - $16,274/ton NO_x; CatOx - $2,095/ton CO
CPV Terrapin, LLC	GA	applic. under review	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 13.6 ppm (NG w/DB); 24 ppm FO	GCP	24-hr rolling	
Kinder Morgan Georgia, LLC - Tift Power	GA	applic. under review	560	7	7	1 - GE 7EA & 6 - LM6000	NG	CC	8,760; 3,760 (part load)	158.5 lb/hr & 141.0 lb/hr	GCP		
Hartwell Development Co.	GA	applic. under review	564	2	0	GE 7FA (176 MW)	NG	CC	8,760	7.4 ppm	GCP		SCONOx - $35,422/ton NO_x; CatOx - $4,964/ton CO

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/ NG	CC	8,760	15/20 ppm	GCP	3-hr	
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Cogentrix Energy, Southaven Power Project	MS	draft permit	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 18 ppm w/ DB	GCP		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	9 ppm	GCP		revised application to add SCR
GenPower - McAdams LLC	MS	draft permit	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	7-8 ppm/13 ppm (w/DB)	GCP	24-hr	
Lone Oak Energy Center	MS	draft permit	800	3	3	F" Class (180 MW)	NG	CC	8,760	10/25/30/17 ppm	GCP		Base/PA/PA+DF/DF
Lee Power Partners	MS	draft permit	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
LSP-Pike Energy LLC	MS	draft permit	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	33.1 ppm (0.15 lb/mmBTU)	GCP		
Magnolia Energy	MS	draft permit	900	3	3	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	20 ppm	GCP		
Reliant Energy - Choctaw Co., LLC	MS	draft permit	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	18.36 ppm	GCP		SCONOx - $48,663/ton NO_x; CatOx - $3,550/ton CO
Crossroads Energy Center	MS	applic. under review	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	10.4 ppm	GCP		SCONOx - $23,400/ton NO_x; CatOx - $11,039/ton CO
Choctaw Gas Generation, LLC	MS	applic. under review	700	2	2	SW 501G (250 MW)	NG	CC	8,760	23 ppm	GCP		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	20.4 ppm	GCP	24-hr	
Granite Power Partners II (Batesville)	MS	applic. under review	300	1	1	SW 501F (230 MW)	NG	CC	8,760	25 ppm	GCP		
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	draft permit	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	15 ppm NG; 20 ppm FO	GCP		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 41 ppm FO	GCP		
GenPower Earleys, LLC	NC	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (14 ppm w/DB)	GCP		SCONOx - $21,942/ton NO_x; CatOx - $3,246ton CO
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	12 ppm NG; 20 ppm FO	GCP		Netted out of NO_x, SO_2 and PM_{10} PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	17.4 ppm NG; 37 pm FO	GCP		SCONOx - no analysis; CatOx - $1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	11.7 ppm	GCP		
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	GCP		
Memphis Generation LLC	TN	draft permit	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	0.03 lb/mmBtu	GCP		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas). Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2001

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Haywood Energy Center (Calpine)	TN	applic. under review	900	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	varies from 7.4 to 50 ppm depending on CT type and load	GCP		
TVA - Franklin	TN	applic. under review	610	2	2	GE 7FA (195 MW)		CC	8,760	25 ppm	GCP		

Abbreviations:
GE = General Electric
SW = Seimens Westinghouse
NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner
SC = Simple Cycle
CC = Combined Cycle
DLN = Dry-Low NOx
WI = Water Injection
SCR = Selective Catalytic Reduction
CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

Table B-8. Direct and Indirect Capital Costs for CO Catalyst, GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$758,000	Vendor Quote
Flue Gas Ductwork	$44,505	Vatavauk, 1990
Instrumentation	$75,800	10% of SCR Associated Equipment
Sales Tax	$45,480	6% of SCR Associated Equipment/Catalyst
Freight	$37,900	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$961,685	
Direct Installation Costs		
Foundation and supports	$76,935	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$134,636	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$38,467	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$19,234	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$9,617	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$9,617	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$293,506	
Total Capital Costs	$1,255,191	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$125,519	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$62,760	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$125,519	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$25,104	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$12,552	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$37,656	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$389,109	
Total Direct, Indirect and Capital Costs (TDICC)	$1,644,300	Sum of TCC and TInCC

Table B-9. Annualized Cost for CO Catalyst GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Direct Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Catalyst Replacement	$219,667	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$24,668	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,545	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$259,056	
Energy Costs		
Heat Rate Penalty	$214,208	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$214,208	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$16,443	1% of Total Capital Costs
Insurance	$16,443	1% of Total Capital Costs
Annualized Total Direct Capital	$180,544	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$217,736	
Total Annualized Costs	$691,000	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$4,165	per ton of CO Removed
	$4,594	per ton of Net Emission Reduction

Table B-10. Comparison of Alternative BACT Control Technologies with Installing OC in HRSG

	Alternative BACT Control Technologies	
	DLN/WI Only	DLN/WI with OC
Technical Assessment	Feasible	Available, Feasible and Demonstrated
Economic Impact [a]		
Capital Costs	included	$1,644,300
Annualized Costs	included	$691,000
Cost Effectiveness		
CO Removed (per ton of CO)	NA	$4,165
Environmental Impact [b]		
Total CO (TPY)	193	27
CO Reduction (TPY)	NA	-165
Net Pollutant Reduction	NA	-150
Additional Greenhouse Gas (CO_2; tons/yr)	--	1,971
Energy Impacts [c]		
Energy Use (kWh/yr)	0	3,021,149
Energy Use (Equivalent Residential Customers/year)	0	252
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	31,121
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	31

[a] See Tables B-8 and B-9 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-11.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty for 8,760 hours per year. Lost energy is based on 0.2 percent of 166 MW.

Table B-11. Maximum Potential Incremental Emissions (TPY) with Oxidation Catalyst

Pollutants		Incremental Emissions (tons/year) of SCR Primary	Secondary	Total
Particulate		11.92	0.11	12.04
Sulfur Dioxide			0.04	0.04
Nitrogen Oxides		0.00	2.07	2.07
Carbon Monoxide		-165.9	1.24	-164.7
Volatile Organic Compounds			0.08	0.08
	Total:	-154.0	3.56	-150.4
Carbon Dioxide (additional from gas firing)			1,971.0	1,971.0

Basis:

Lost Energy (mmBtu/year)	31,121

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

APPENDIX C

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

C.1 INTRODUCTION

As part of the new source review requirements under Prevention of Significant Deterioration (PSD) regulations, new sources are required to address air quality impacts at PSD Class I areas. As part of the PSD analysis report submitted to the Florida Department of Environmental Protection (DEP), the air quality impacts due to the potential emissions of the proposed FPL Martin project are required to be addressed at the PSD Class I area of the Everglades National Park (ENP). The ENP is located approximately 144 km south of the facility site and is the only PSD Class I area within 200 km of the facility.

The evaluation of air quality impacts are not only concerned with determining compliance with PSD Class I increments but also assessing a source's impact on Air Quality Related Values (AQRVs), such as regional haze. Further, compliance with PSD Class I increments can be evaluated by determining if the source's impacts are less than the proposed U.S. Environmental Protection Agency (EPA) Class I significant impact levels. The significant impact levels are threshold levels that are used to determine the type of air impact analyses needed for the facility. If the new source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with Class I increments.

Currently there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and Federal Land Managers (FLM) of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report.
- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report,* USFS, NPS, USFWS (12/00), referred to as the FLAG document.

For the proposed project, air quality analyses were performed that assess the facility's impacts in the PSD Class I area of the ENP using the refined modeling approach from the IWAQM Phase 2 report for:

- Significant impact analysis
- SO_2 PSD Class I increment analysis; and
- Regional haze analysis

The refined analysis approach was used instead of the screening analysis approach since the air quality impacts are based on generally more realistic assumptions, include more detailed meteorological data, and are estimated at locations at the Class I area.

C.2 GENERAL AIR MODELING APPROACH

The general modeling approach was based on using the long-range transport model, California Puff model (CALPUFF, Version 5.4). At distances beyond 50 km, the ISCST3 model is considered to over-predict air quality impacts, because it is a steady-state model. At those distances, the CALPUFF model is recommended for use. Recently, the FLM have requested that air quality impacts, such as for regional haze, for a source located more than 50 km from a Class I area be predicted using the CALPUFF model. The Florida DEP has also recommended that the CALPUFF model be used to assess if the source has a significant impact at a Class I area located beyond 50 km from the source. As a result, a significant impact and regional haze analyses were performed using the CALPUFF model to assess the facility's impacts at the ENP.

The methods and assumptions used in the CALPUFF model were based on the latest recommendations for a refined analysis as presented in the IWAQM Phase 2 Summary Report and the FLAG documents.

A regional haze analysis was performed to determine the affect that the facility's emissions will have on background regional haze levels at the ENP. In the regional haze analysis, the change in visual range, as calculated by a deciview change, was estimated for the facility in accordance with the IWAQM recommendations. Based on those recommendations, the CALPUFF model is used to predict the maximum 24-hour average sulfate (SO_4), nitrate (NO_3), and fine particulate (PM_{10}) concentrations as well as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium nitrate (NH_4NO_3) concentrations. The change in visibility due to a source, estimated as a percentage, is then calculated based on the change from background data.

The following sections present the methods and assumptions used to assess the refined significant impact and regional haze analyses performed for the Proposed Project. The results of these analyses are presented in Sections 6.0 and 7.0 of the PSD report.

C.3 MODEL SELECTION AND SETTINGS

The California Puff (CALPUFF, version 5.4) air modeling system was used to model to assess the Proposed Project's impacts at the PSD Class I area for comparison to the PSD Class I significant impact levels and to the regional haze visibility criteria. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALPUFF meteorological and geophysical data preprocessor (CALMET, Version 5.2), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. CALMET was designed to process raw meteorological, terrain and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET was input to CALPUFF to assess the pollutant specific impact. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase 2 and FLAG reports.

C.3.1 CALPUFF MODEL APPROACHES AND SETTINGS

The IWAQM has recommended approaches for performing a Phase 2 refined modeling analyses that are presented in Table 1. These approaches involve use of meteorological data, selection of receptors and dispersion conditions, and processing of model output.

The specific settings used in the CALPUFF model are presented in Table 2.

C.3.2 EMISSION INVENTORY AND BUILDING WAKE EFFECTS

The CALPUFF model included the facility's emission, stack, and operating data as well as building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and were included in the CALPUFF model input. The PSD Analysis Report presents a listing of the facility's emissions and structures included in the analysis.

C.4 RECEPTOR LOCATIONS

For the refined analyses, pollutant concentrations were predicted in an array of 126 discrete receptors located at the ENP area. These receptors are the same as those used in the PSD Class I analysis performed for the PSD Analysis Report.

C.5 METEOROLOGICAL DATA

C.5.1 REFINED ANALYSIS

CALMET was used to develop the gridded parameter fields required for the refined modeling analyses. The follow sections discuss the specific data used and processed in the CALMET model.

C.5.2 CALMET SETTINGS

The CALMET settings contained in Table 3 were used for the refined modeling analysis. With the exception of hourly precipitation data files, all input data files needed for CALMET were developed by the FDEP staff.

C.5.3 MODELING DOMAIN

A rectangular modeling domain extending 450 km in the east-west (x) direction and 470 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 23.8 degrees north latitude and 83.5 degrees west longitude. This location is in the Gulf of Mexico approximately 110 km west of Venice, Florida. For the processing of meteorological and geophysical data, the domain contains 90 grid cells in the x-direction and 94 grid cells in the y-direction. The domain grid resolution is 5 km. The air modeling analysis was performed in the UTM coordinate system.

C.5.4 MESOSCALE MODEL – GENERATION 4 (MM4) DATA

Pennsylvania State University in conjunction with the NCAR Assessment Laboratory developed the MM4 data set, a prognostic wind field or "guess" field, for the United States. The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for one data base set for the year 1990. The analysis used the MM4 data to initialize the CALMET wind field. The MM4 data have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain.

The MM4 subset domain was provided by FDEP and consisted of a 7 x 7- cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (50,6) to (57,13). These data were processed to create a MM4.DAT file, for input to the CALMET model.

The MM4 data set used in the CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

C.5.5 SURFACE DATA STATIONS AND PROCESSING

The surface station data processed for the CALPUFF analyses consisted of data from eight NWS stations or Federal Aviation Administration (FAA) Flight Service stations for Orlando, Fort Myers, Daytona Beach, Vero Beach, Key West, Miami, Tampa, and West Palm Beach. A summary of the surface station information and locations are presented in Table 4. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The surface station data were processed by FDEP into a SURF.DAT file format for CALMET input.

Because the modeling domain extends largely over water, C-Man station data from Venice, Sombrero Key, and Lake Worth was obtained. These data were processed by Florida DEP into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. The over-water station data include wind direction, wind speed and air temperature.

C.5.6 UPPER AIR DATA STATIONS AND PROCESSING

The analysis included three upper air NWS stations located in Ruskin, Key West, and West Palm Beach. Data for each station were obtained from the Florida DEP in a format for CALMET input. The data and locations for the upper air stations are presented in Table 4.

C.5.7 PRECIPITATION DATA STATIONS AND PROCESSING

Precipitation data were processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation-recording stations located within the latitude and longitudinal limits of the modeling domain. Data for 23 stations were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were then used to process the data into the format for the PRECIP.DAT file that is used by CALMET. A listing of the precipitation stations used for the modeling analysis is presented in Table 5.

C.5.8 GEOPHYSICAL DATA PROCESSING

Terrain elevations for each grid cell of the modeling domain were obtained from 1-degree Digital Elevation Model (DEM) files obtained from the U.S. Geographical Survey (USGS) internet website. The DEM data was extracted for the modeling domain grid using the utility program TERREL. Land-use data were also extracted from 1-degree USGS files and processed using utility programs CTGCOMP and CTGPROC. Both the terrain and land use files were combined into a GEO.DAT file for input to CALMET with the MAKEGEO utility program.

Table 1. Refined Modeling Analyses Recommendations [a]

Model Input/Output	Description
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; obtain regulatory concurrence on coverage.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition. 3. Define background values for ozone and ammonia for area.
Processing	1. For PSD increments: use highest, second highest 3-hour and 24-hour average SO_2 concentrations; highest, second highest 24-hour average PM_{10} concentrations; and highest annual average SO_2, PM_{10} and NO_x concentrations. 2. For haze: process, on a 24-hour basis, compute the source extinction from the maximum increase in emissions of SO_2, NO_x and PM_{10}; compute the daily relative humidity factor [f(RH)], provided from an external disk file; and compute the maximum percent change in extinction using the FLM supplied background extinction data in the FLAG document. 3. For significant impact analysis: use highest annual and highest short-term averaging time concentrations for SO_2, PM_{10} and NO_x.

[a] IWAQM Phase II report (December, 1998) and FLAG document (December, 2000)

Table 2. CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}
Chemical Transformation	MESOPUFF II scheme, hourly ozone data
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG /MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration file including output species for SO_4, NO_3, PM_{10}, SO_2, and NO_x; process for visibility change using Method 2 and FLAG background extinctions
Model Processing	For haze: highest predicted 24-hour extinction change (%) for the year For deposition: annual average deposition rate For significant impact analysis: highest predicted annual and highest short-term averaging time concentrations for SO_2, NO_x, and PM_{10}.
Background Values	Ozone: 80 ppb; Ammonia: 1 ppb

[a] Recommended values by the Florida DEP.

Table 3. CALMET Settings

Parameter	Setting
Horizontal Grid Dimensions	450 by 470 km, 5 km grid resolution
Vertical Grid	9 layers
Weather Station Data Inputs	8 surface, 3 upper air, 23 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 7 x 7 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

Table 4. Surface and Upper Air Stations Used in the CALPUFF Analysis

Station Name	Station Symbol	WBAN Number	UTM Coordinates Easting (km)	Northing (km)	Zone	Anemometer Height (m)
Surface Stations						
Tampa	TPA	12842	349.20	3094.25	17	6.7
Daytona Beach	DAB	12834	495.14	3228.05	17	9.1
Orlando	ORL	12815	468.96	3146.88	17	10.1
Vero Beach	VER	12843	557.52	3058.36	17	6.7
Fort Myers	FMY	12835	413.65	2940.38	17	6.1
Miami	MIA	12839	566.82	2857.20	17	7.0
Key West	EYW	12836	424.03	2715.14	17	18.3
West Palm Beach	PBI	12844	587.87	2951.43	17	10.1
Upper Air Stations						
Ruskin	TBW	12842	349.20	3094.28	17	NA
West Palm Beach	PBI	12844	587.87	2951.42	17	NA
Key West	EYW	12836	424.03	2715.14	17	NA

Table 5. Hourly Precipitation Stations Used in the CALPUFF Analysis

Station Name	Station Number	UTM Coordinate Easting (km)	UTM Coordinate Northing (km)	Zone
Belle Glade HRCN GT 4	80616	528.19	2953.03	17
Boca Raton	80845	588.75	2916.52	17
Canal Point Gate 5	81271	536.43	2971.51	17
Clewiston US Engineers	81654	546.19	2912.73	17
Fort Myers FAA/AP	83186	413.99	2940.71	17
Homestead Exp Stn	84091	550.26	2820.21	17
Key West Intl AP	84570	423.67	2715.51	17
Miami WSCMO Airport	85663	570.20	2856.17	17
Moore Haven Lock 1	85895	491.61	2967.80	17
North New River Canal #	86323	546.58	2912.48	17
Ortona Lock 2	86657	470.17	2962.27	17
Parrish	86880	366.99	3054.39	17
Pennsuco 5 WNW	86988	554.70	2867.81	17
Port Mayaca S l Canal	87293	538.04	2984.44	17
St Lucie New Lock 1	87859	571.04	2999.35	17
St Petersburg	87886	339.61	3071.99	17
Tamiami Trail 40 Mi BEN	88780	517.64	2849.04	17
Tampa WSCMO AP	88788	348.48	3093.67	17
Trail Glade Ranges	89010	551.57	2849.99	17
Venice	89176	357.59	2998.18	17
Venus	89184	467.27	3001.22	17
Vero Beach 4 W	89219	554.27	3056.50	17
West Palm Beach Int AP	89525	589.61	2951.63	17

APPENDIX D

SO_2 EMISSION DATA FOR BACKGROUND SOURCES

Table D-1. Summary of SO_2 Sources Included in the Air Modeling Analysis

AIRS Number	Facility	Units	Modeling ID Name	Relative Location X (km)	Relative Location Y (km)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Class II	Class I
0850001	FPL Martin													
		Units 1&2	MART12	-0.168	0.601	152.1	7.99	420.9	21.03	1743.79	NO	Yes	No	No
		Aux Blr PSD	MARTAUX	-0.046	0.162	18.3	1.10	535.4	15.24	12.90	CON	Yes	Yes	Yes
		Diesel Gens PSD	MARTGEN	-0.046	0.162	7.6	0.30	785.9	39.62	0.51	CON	Yes	Yes	Yes
		Units 3&4 PSD	MART34	-0.046	0.162	64.9	6.10	410.9	18.90	470.40	CON	Yes	Yes	Yes
0850102	Bechtel Indiantown PSD		BECHTIND	2.5	-1.4	150.9	4.88	333.2	30.50	75.64	CON	Yes	Yes	Yes
990021	Pratt & Whitney													
		Heater	PRATARCH	16.1	-14.6	15.2	0.91	810.9	143.73	13.99	CON	Yes	Yes	Yes
		Boiler BO-12	PRATBO12	16.1	-14.6	4.6	0.76	533.2	6.92	0.51	CON	Yes	Yes	Yes
0990019	Osceola Farms [a]													
		Unit 2	OSBLR2	1.1	-24.9	27.4	1.52	339.0	18.63	17.12	CON	Yes	Yes	Yes
		Unit 3	OSBLR3	1.1	-24.9	27.4	1.92	344.0	14.34	30.74	CON	Yes	Yes	Yes
		Unit 4	OSBLR4	1.1	-24.9	27.4	1.83	344.0	16.53	17.12	CON	Yes	Yes	Yes
		Unit 5	OSBLR5	1.1	-24.9	27.4	1.52	344.0	17.85	18.00	CON	Yes	Yes	Yes
		Unit 6	OSBLR6	1.1	-24.9	27.4	1.92	339.0	18.25	33.39	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	OSBLR1B	1.1	-24.9	22.0	1.52	342.0	8.18	-5.07	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	OSBLR2B	1.1	-24.9	22.0	1.52	341.0	18.10	-16.32	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	OSBLR3B	1.1	-24.9	22.0	1.93	341.0	14.50	-7.26	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	OSBLR4B	1.1	-24.9	22.0	1.83	341.0	18.80	-13.61	EXP	No	Yes	Yes
0990061	US Sugar-Bryant [a]													
		Unit 5 PSD	USSBRY5	-4.3	-24.8	42.7	2.90	345.0	11.49	45.70	CON	Yes	Yes	Yes
		Unit 1,2&3	USBRY123	-4.3	-24.8	19.8	1.64	342.0	36.40	109.50	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	USSBRY1B	-4.3	-24.8	19.8	1.68	494.0	44.30	-36.50	EXP	No	Yes	Yes
		Unit 2&3 PSD Baseline	USBRY23B	-4.3	-24.8	19.8	1.68	344.0	37.90	-73.00	EXP	No	Yes	Yes
0990026	Sugar Cane Growers [a]													
		Unit 1&2	SUGCN12	-8.2	-39.6	45.7	1.87	339.0	21.75	41.20	CON	Yes	Yes	Yes
		Unit 3	SUGCN3	-8.2	-39.6	27.4	1.52	339.0	22.25	16.20	CON	Yes	Yes	Yes
		Unit 4 PSD	SUGCN4	-8.2	-39.6	54.9	2.44	339.0	21.73	38.20	CON	Yes	Yes	Yes
		Unit 5	SUGCN5	-8.2	-39.6	45.7	2.30	339.0	15.94	27.90	CON	Yes	Yes	Yes
		Unit 8 PSD	SUGCN8	-8.2	-39.6	47.2	2.90	339.0	13.62	23.50	CON	Yes	Yes	Yes
		Unit 1&2 PSD Baseline	SUGCN12B	-8.2	-39.6	24.4	1.40	344.0	11.40	-24.20	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	SUGCN3B	-8.2	-39.6	24.4	1.60	344.0	15.60	-4.40	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	SUGCN4B	-8.2	-39.6	25.9	1.63	344.0	11.20	-24.20	EXP	No	Yes	Yes
		Unit 5 PSD Baseline	SUGCN5B	-8.2	-39.6	24.4	1.40	344.0	15.20	-16.20	EXP	No	Yes	Yes
		Unit 6&7 PSD Baseline	SUGCN67B	-8.2	-39.6	12.2	1.52	606.0	11.20	-51.00	EXP	No	Yes	Yes
0990016	Atlantic Sugar [a]													
		Unit 1	ATLSUG1	9.8	-47.7	27.4	1.83	346.0	17.97	16.28	CON	Yes	Yes	Yes
		Unit 2	ATLSUG2	9.8	-47.7	27.4	1.83	350.0	23.36	16.28	CON	Yes	Yes	Yes
		Unit 3	ATLSUG3	9.8	-47.7	27.4	1.83	350.0	21.56	16.02	CON	Yes	Yes	Yes
		Unit 4	ATLSUG4	9.8	-47.7	27.4	1.83	344.0	25.16	16.21	CON	Yes	Yes	Yes
		Unit 5 PSD [b]	ATLSUG5	9.8	-47.7	27.4	1.68	339.0	19.24	8.04	CON	Yes	Yes	Yes
		Unit 1 PSD Baseline	ATLSUG1B	9.8	-47.7	18.9	1.92	506.0	12.70	-17.24	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	ATLSUG2B	9.8	-47.7	18.9	1.92	511.0	10.90	-22.50	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	ATLSUG3B	9.8	-47.7	21.9	1.83	522.0	17.50	-16.88	EXP	No	Yes	Yes
		Unit 4 PSD Baseline	ATLSUG4B	9.8	-47.7	18.3	1.83	344.0	15.00	-10.76	EXP	No	Yes	Yes
	Fort Pierce Utilities													
		Units 6&7	FTPIER67	23.7	43.4	45.7	2.19	408.2	12.50	77.87	NO	Yes	No	No
0510001	Everglades Sugar [b]	Main Boiler	EVERGLAD	-33.5	-38.7	21.9	1.10	477.0	10.10	34.90	NO	Yes	No	No

Table D-1. Summary of SO_2 Sources Included in the Air Modeling Analysis

AIRS Number	Facility	Units	Modeling ID Name	Relative Location X (km)	Relative Location Y (km)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Class II	Class I
0510003	US Sugar - Clewiston[d]													
		PSD Baseline (On-crop season only)												
		Unit 1 PSD Baseline	USSBRL1B	-37	-36	23 1	1 86	344 0	30 20	-58 21	EXP	No	Yes	Yes
		Unit 2 PSD Baseline	USSBLR2B	-37	-36	23.1	1 86	343 0	35 70	-58 21	EXP	No	Yes	Yes
		Unit 3 PSD Baseline	USSBLR3B	-37	-36	27 4	2 29	342.0	14 70	-33 20	EXP	No	Yes	Yes
		East Pellet Plant PSD Baseline	EPELLET	-37	-36	12.2	1.52	347.0	8.54	-10 30	EXP	No	Yes	Yes
		West Pellet Plant PSD Baseline	WPELLET	-37	-36	15 7	1.52	347 0	8 54	-10 30	EXP	No	Yes	Yes
		On-crop season future												
		Unit 1	USSBRL1N	-37	-36	65 0	2 44	347.0	15 36	73 73	CON	Yes	Yes	Yes
		Unit 2	USSBLR2N	-37	-36	65 0	2 44	338 0	13 86	73 44	CON	Yes	Yes	Yes
		Unit 3	USSBLR3N	-37	-36	65 0	2 44	333 2	6 78	47.08	CON	Yes	Yes	Yes
		Unit 4	USSBLR4N	-37	-36	45 7	2.51	344 3	20 28	3 68	CON	Yes	Yes	Yes
		Unit 7	USSBLR7N	-37	-36	68 6	2 59	405 4	20.77	12 65	CON	Yes	Yes	Yes
		Off-crop season future												
		Unit 1	USSBRL1F	-37	-36	65 0	2 44	347.0	14 05	24 29	CON	Yes	Yes	Yes
		Unit 2	USSBLR2F	-37	-36	65 0	2 44	338.0	12 68	24 02	CON	Yes	Yes	Yes
		Unit 3	USSBLR3F	-37	-36	65.0	2 44	333 2	6 20	30 20	CON	Yes	Yes	Yes
		Unit 4	USSBLR4F	-37	-36	45 7	2 51	344 3	0 00	0 00	CON	Yes	Yes	Yes
		Unit 7	USSBLR7F	-37	-36	68 6	2 59	405 4	23 60	15 81	CON	Yes	Yes	Yes
0990234	Palm Beach Co. Resource Recovery													
		1&2 PSD	PBCRRF	42.7	-32.7	76.2	2 04	505 2	24 90	85 05	CON	Yes	Yes	Yes
0990042	FPL Riviera[c]													
		Units 3&4 at 2 5%s fuel oil	RIVU34	51.1	-32 3	90 8	4 88	401.5	18 90	2113 65	NO	Yes	No	No
	Vero Beach Power[c]													
		Unit 1	VERBU1	24	63 6	60.96	1.07	437 0	32 42	28.77	NO	Yes	No	No
		Unit 2	VERBU2	24	63 6	60 96	1 07	434 3	37.57	84.21	NO	Yes	No	No
		Unit 3	VERBU3	24	63 6	60.96	1 83	440 4	19 93	142 07	NO	Yes	No	No
		Unit 4	VERBU4	24	63 6	60 96	2 13	425 4	24 36	69 05	NO	Yes	No	No
		Unit 5 Simple Cycle CT	VERBU5	24	63 6	38 10	3 35	416 5	19.56	15.50	CON	Yes	Yes	No
0990568	Lake Worth Utilities[c]													
		Unit 3	LAKWTHU3	49 7	-49 2	38.1	2.13	408 2	7.71	103 95	NO	Yes	No	No
		Unit 4	LAKWTHU4	49 7	-49.2	35.1	2 29	418 2	17 00	129 85	NO	Yes	No	No
		Unit 5	LAKWTHU5	49 7	-49.2	22.9	0 94	450.4	18 29	11 59	NO	Yes	No	No
		HRSG	LAKWTHHR	49 7	-49 2	45.7	5 49	377 6	13 74	12 79	CON	Yes	Yes	Yes
0250348	Dade County RRF PSD													
		Units 1&2	DCRRF12	21.2	-135 5	76 2	3 66	405 4	15 86	12 32	CON	No[e]	No[e]	Yes
		Units 3&4	DCRRF34	21.2	-135 5	76 2	3 66	405.4	15 86	12 32	CON	No[e]	No[e]	Yes
0250020	Tarmac													
		Kiln 1	TARMC1	19.8	-131.2	61 0	2 44	465.0	12 80	5 67	NO	No[e]	No[e]	No
		Kiln 2 PSD Baseline	TARMC2B	19.8	-131.2	61.0	2 44	465 0	12 84	-5.71	EXP	No[e]	No[e]	Yes
		Kiln 3 PSD Baseline	TARMC3B	19.8	-131 2	61.0	4 57	472 0	10 78	-2.76	EXP	No[e]	No[e]	Yes
		Kiln 2 PSD	TABMC2P	19 8	-131 2	61 0	2 44	422 0	9 10	24 57	CON	No[e]	No[e]	Yes
		Kiln 3 PSD	TARMC3P	19.8	-131 2	61 0	4 57	450 0	11 04	51 43	CON	No[e]	No[e]	Yes
0112119	South Broward RRF PSD		SBCRRF	36.5	-109 6	59 4	3 96	381.0	18 01	37.91	CON	No[e]	No[e]	Yes

Table D-1. Summary of SO_2 Sources Included in the Air Modeling Analysis

AIRS Number	Facility	Units	Modeling ID Name	Relative Location X (km)	Relative Location Y (km)	Stack and Operating Parameters Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate(g/s) 24-Hour	PSD Source? (EXP/CON)	Modeled in AAQS	Class II	Class I
0110037	FPL - Lauderdale													
		CTs 1-4 PSD	LAUDU45	37	-109 6	45.7	5 49	438 7	14 60	271.15	CON	No [e]	No [e]	Yes
		GT 1-12 (0 5% fuel oil)	LDGT1_12	37	-109 6	13.7	2.37	733 2	114.31	552 80	NO	No [e]	No [e]	No
		GT 13-24 (0.5% fuel oil)	LDGT1324	37	-109 6	13 4	4 75	733 2	28 43	552.80	NO	No [e]	No [e]	No
		4&5 PSD Baseline	FTLAU45B	37	-109 6	46 0	4 27	422 0	14 63	-457.00	EXP	No [e]	No [e]	Yes
110120	North Broward RRF PSD		NBCRRF	40 5	-85 3	58 5	3 96	381 0	18 01	35 40	CON	No [e]	No [e]	Yes
0710019	Lee County RRF PSD		LEECORRF	44 3	-107.6	83 8	1.88	388 5	19 81	14 00	CON	No [e]	No [e]	Yes
50PMB500332	Okeelanta [a]													
		Boiler 4 PSD Baseline	OKBLR4B	-18.1	-55.5	22 9	2 29	333 0	7 36	-10.95	EXP	No [e]	No [e]	Yes
		Boiler 5 PSD Baseline	OKBLR5B	-18 1	-55.5	22 9	2 29	333 0	12 07	-15 64	EXP	No [e]	No [e]	Yes
		Boiler 6 PSD Baseline	OKBLR6B	-18 1	-55.5	22 9	2 29	334 0	8 74	-15 64	EXP	No [e]	No [e]	Yes
		Boiler 10 PSD Baseline	OKBLR10B	-18 1	-55 5	22.9	2 29	334 0	10 35	-17 15	EXP	No [e]	No [e]	Yes
		Boiler 11 PSD Baseline	OKBLR11B	-18.1	-55 5	22 9	2 29	342 0	9 89	-16 79	EXP	No [e]	No [e]	Yes
		Boiler 16 PSD	OKBLR16	-18.1	-55 5	22.9	1.52	483 0	22 86	-1.47	CON	No [e]	No [e]	Yes
		Okeelanta Power Blrs 1,2,3 [b]	OKCOGENF	-18 1	-55.5	60.7	3.05	450.9	19 .39	54 1	CON	No [e]	No [e]	Yes
0710000	FPL Fort Myers													
		Unit 1 PSD	FMU1	-121	-40	91.8	2.90	422 0	29 90	-585 50	EXP	No [e]	No [e]	Yes
		Unit 2 PSD	FMU2	-121	-40	121 2	5 52	408 0	19 20	-1334 0	EXP	No [e]	No [e]	Yes
		HRSGs 1 - 6	FMYHR1_6	-121	-40	38 1	5 79	377 6	14 2	3 9	CON	No [e]	No [e]	Yes
		Gas Turbines 1 -12	FMYGT112	-121	-40	9.75	4 42	797 0	35 7	649 2	NO	No [e]	No [e]	No
50FTM260015	Southern Gardens Citrus - PSD													
		Peel Dryer	SGARDDRY	-55 5	-35 3	38.1	1.73	316 0	7.45	5 29	CON	No [e]	No [e]	Yes
		Boilers 1-3	SGARDBLR	-55.5	-35 3	16.8	1.22	478 0	14 22	6 88	CON	No [e]	No [e]	Yes

Note
EXP = PSD expanding source
CON = PSD consuming source
NO = Source does not affect PSD increment

[a] Facilities or sources within facilities that operate only during the October 1 through April 31 crop season

[b] Sugar mill sources that operate all year.

[c] Large source with emissions greater than 1,000 TPY included in the AAQS or PSD Class II modeling even though the source is located outside of the screening area

[d] Represents worst case emissions for May 1 through September 31 off-crop season operation, and October 1-April 30 for on-crop season.
Updated from PSD modeling information, Golder Associates (7/18/00) Baseline data represents November 1 though April 30.

[e] Not included in the AAQS or PSD Class II modeling because these sources were screened out using the North Carolina Screening Technique or located more than 100 km from the modeling area.

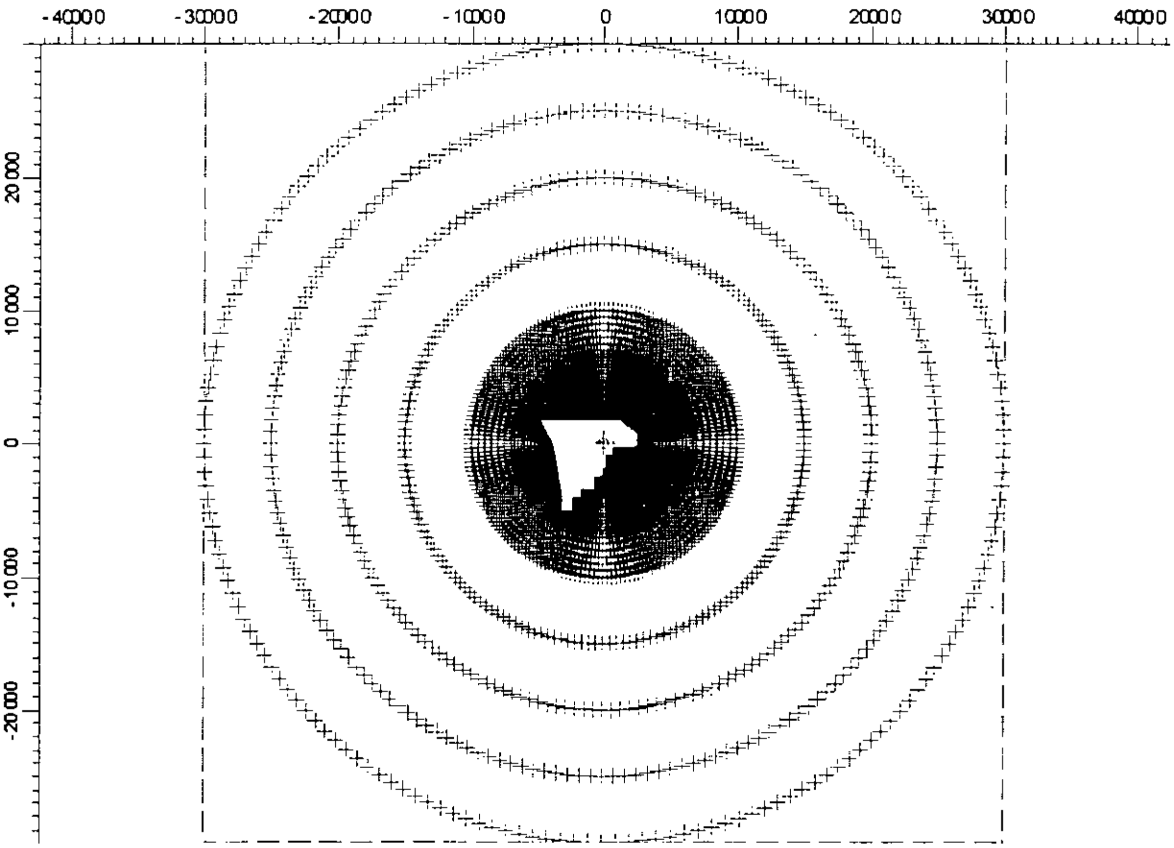
APPENDIX E

RECEPTOR LOCATION FIGURES AND BUILDING PROFILE INPUT PROGRAM (BPIP) FILES

GENERIC MAXIMUM
IMPACT RECEPTOR GRID

PROJECT TITLE :

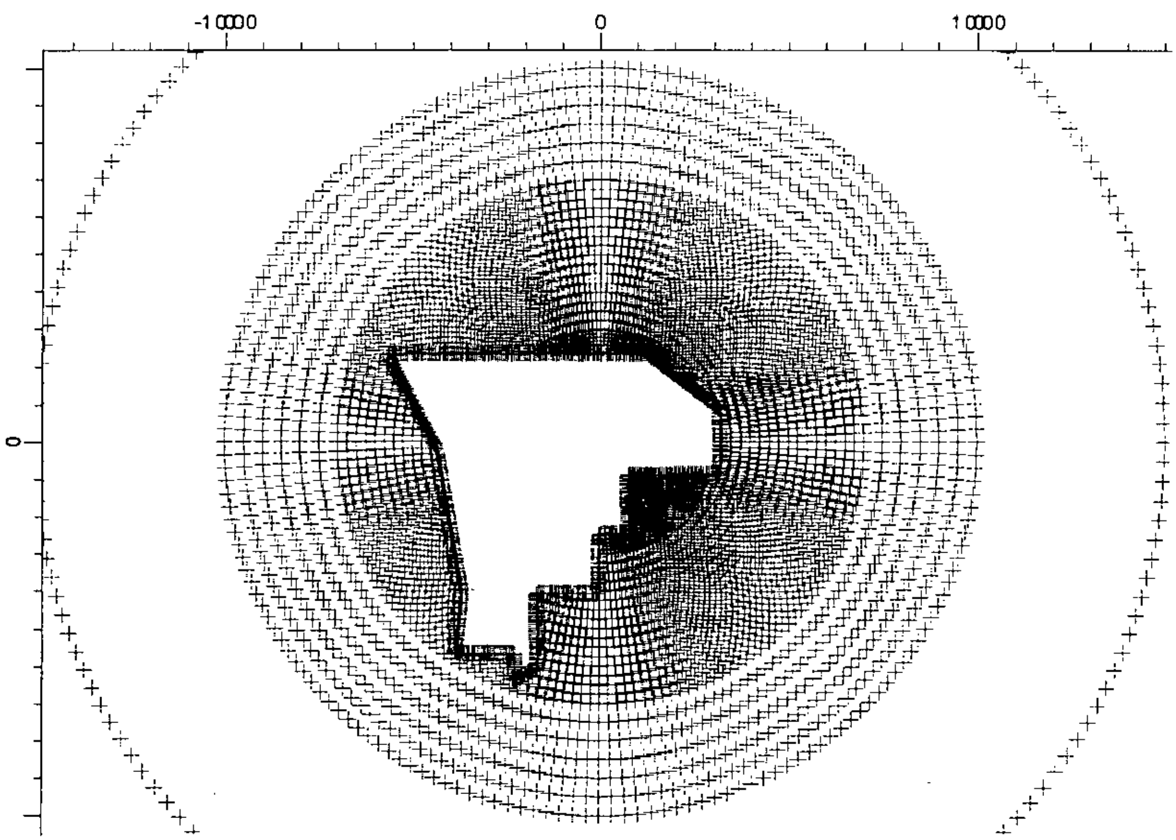
Maximum Impact Receptor Grid



COMMENTS :	SOURCES	COMPANY NAME :	
	6	**Golder Associates, Inc.**	
	RECEPTORS .	MODELER	SCALE .
	5526	**Larocca**	0 ___ 10 km
		DATE :	PROJECT NO :
		1/17/02	

PROJECT TITLE :

Maximum Impact Receptor Grid



COMMENTS :	SOURCES :	COMPANY NAME :	
	6	**Golder Associates, Inc.**	
	RECEPTORS : 5526	MODELER : **Larocca**	SCALE : 0 ___ 5 km
		DATE : 1/17/02	PROJECT NO. :

ISCAERMOD View - Lakes Environmental Software

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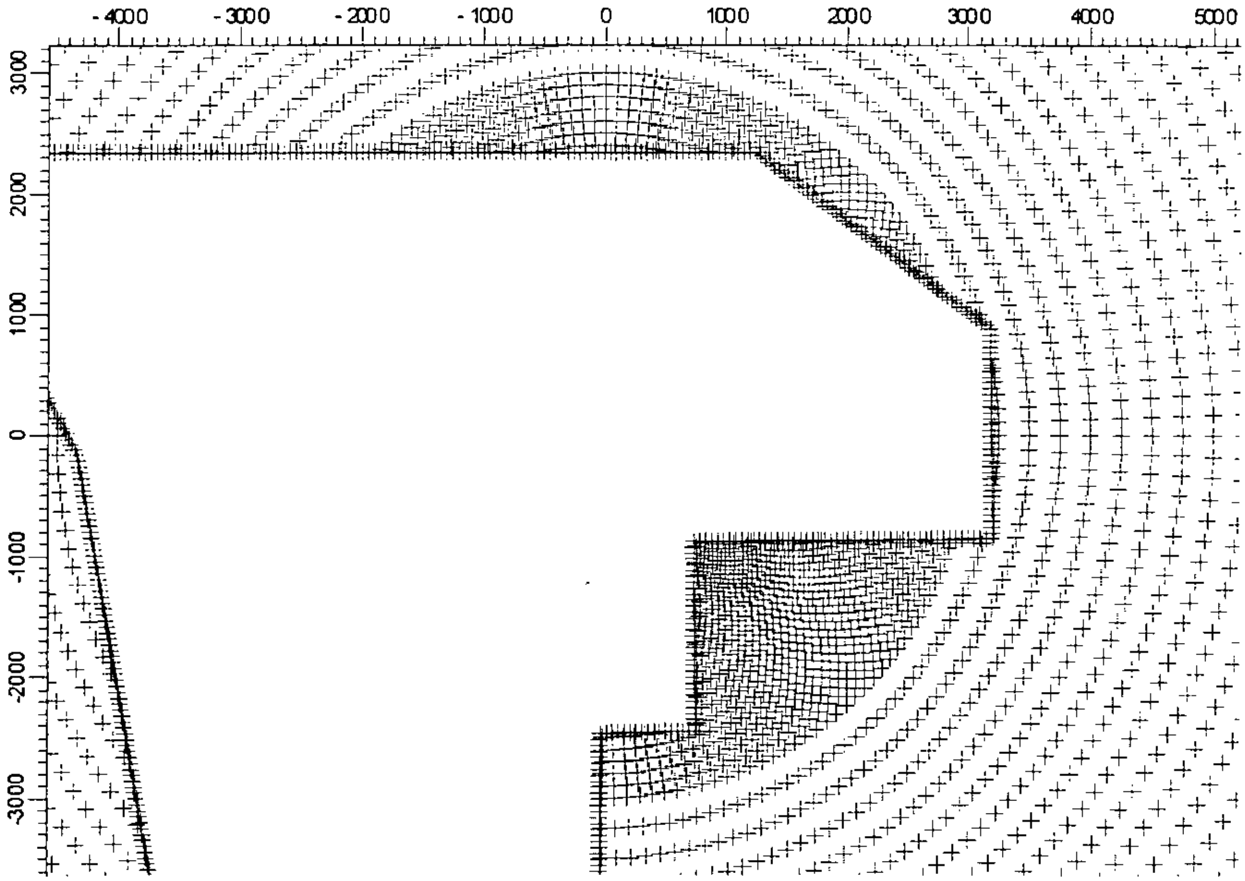
PROJECT TITLE:

Maximum Impact Receptor Grid



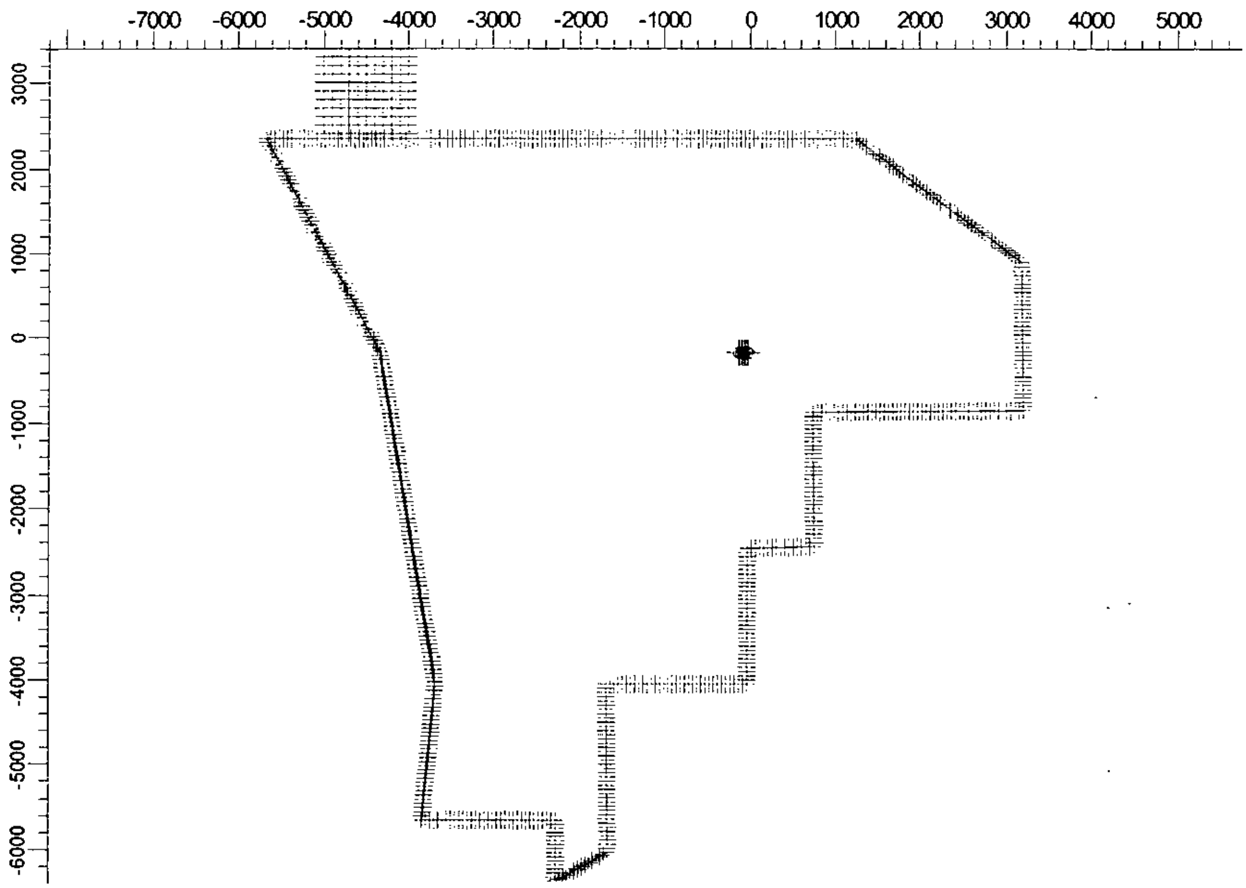
COMMENTS:	SOURCES: 6	COMPANY NAME: Golder Associates, Inc.	
	RECEPTORS: 5526	MODELER: Larocca	SCALE: 0 ▬ 1 km
		DATE: 1/17/02	PROJECT NO.:

ISC-AERMOD View - Lakes Environmental Software D:\maron\maron3.isc

REFINED PM_{10}
RECEPTOR GRIDS

PROJECT TITLE :

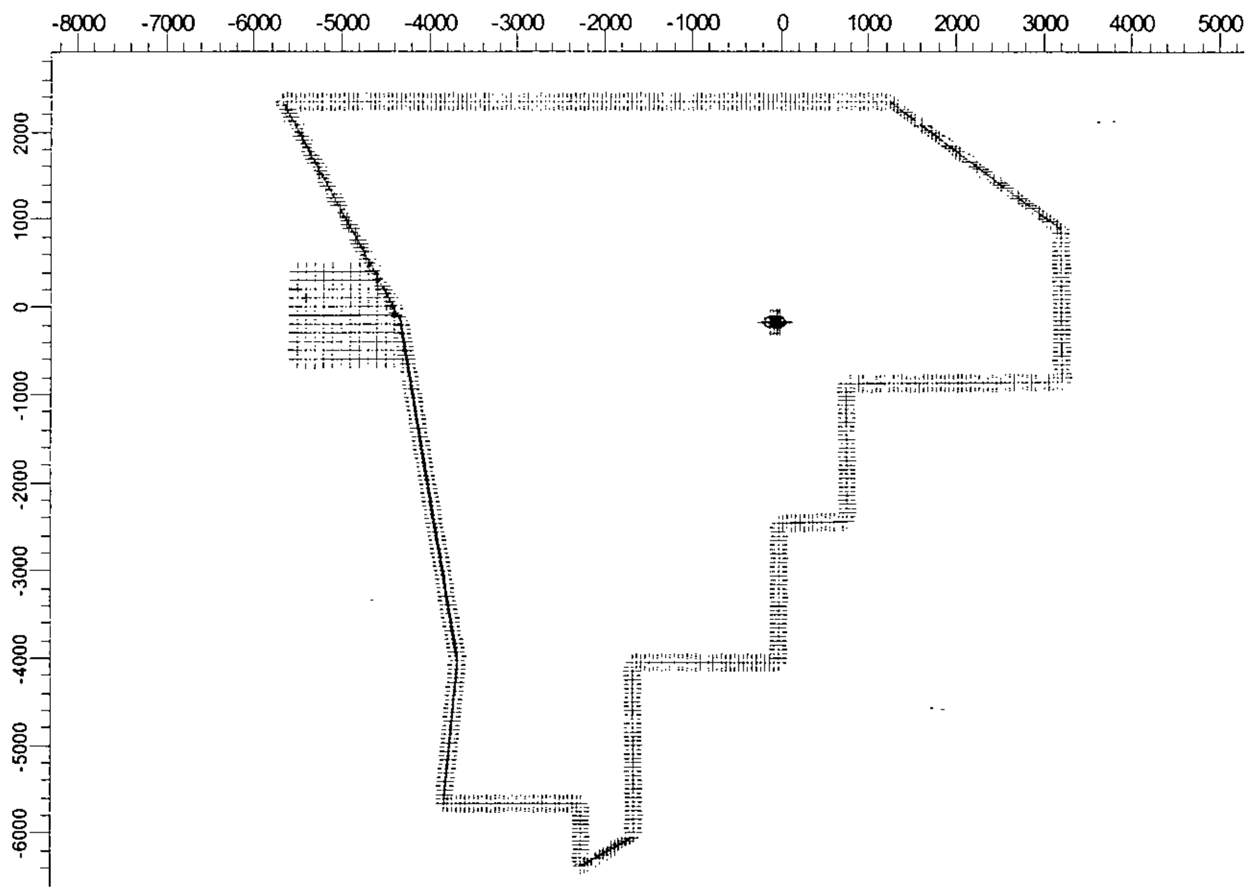
Refined PM Analysis Receptor Grid
1990 Annual Impacts



COMMENTS :	SOURCES : 18	COMPANY NAME : **Golder Associates, Inc.**	
	RECEPTORS : 778	MODELER : **Larocca**	SCALE : 0 ▬ 2 km
		DATE : **1/24/02**	PROJECT NO. :

PROJECT TITLE :

Refined PM Analysis Receptor Grid
1987 24-hour Impacts



COMMENTS :	SOURCES : 18	COMPANY NAME : Golder Associates, Inc.	
	RECEPTORS : 783	MODELER : Larocca	SCALE : 0 — 2 km
		DATE : 1/24/02	PROJECT NO. :

ISC-AERMOD View - Lakes Environmental Software

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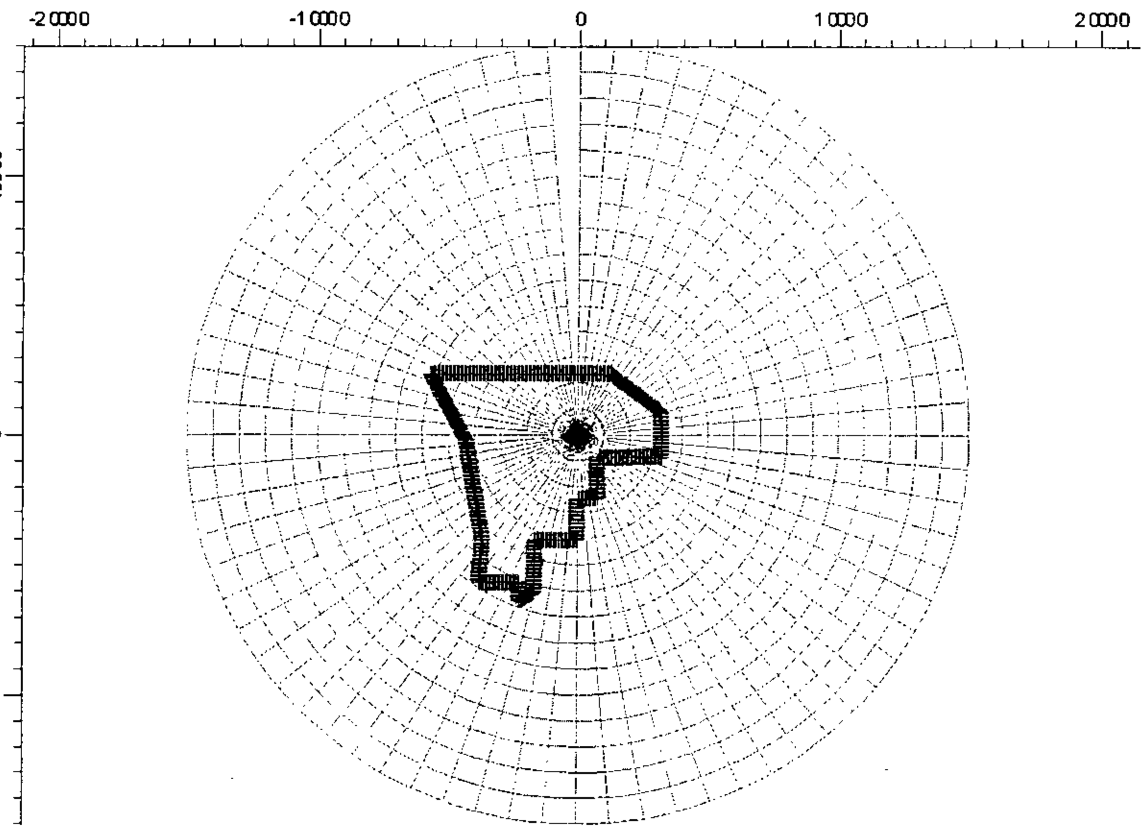
SIGNIFICANT IMPACT AREA
POLAR RECEPTOR GRID

PROJECT TITLE

Significant Impact Area Analysis Polar Grid

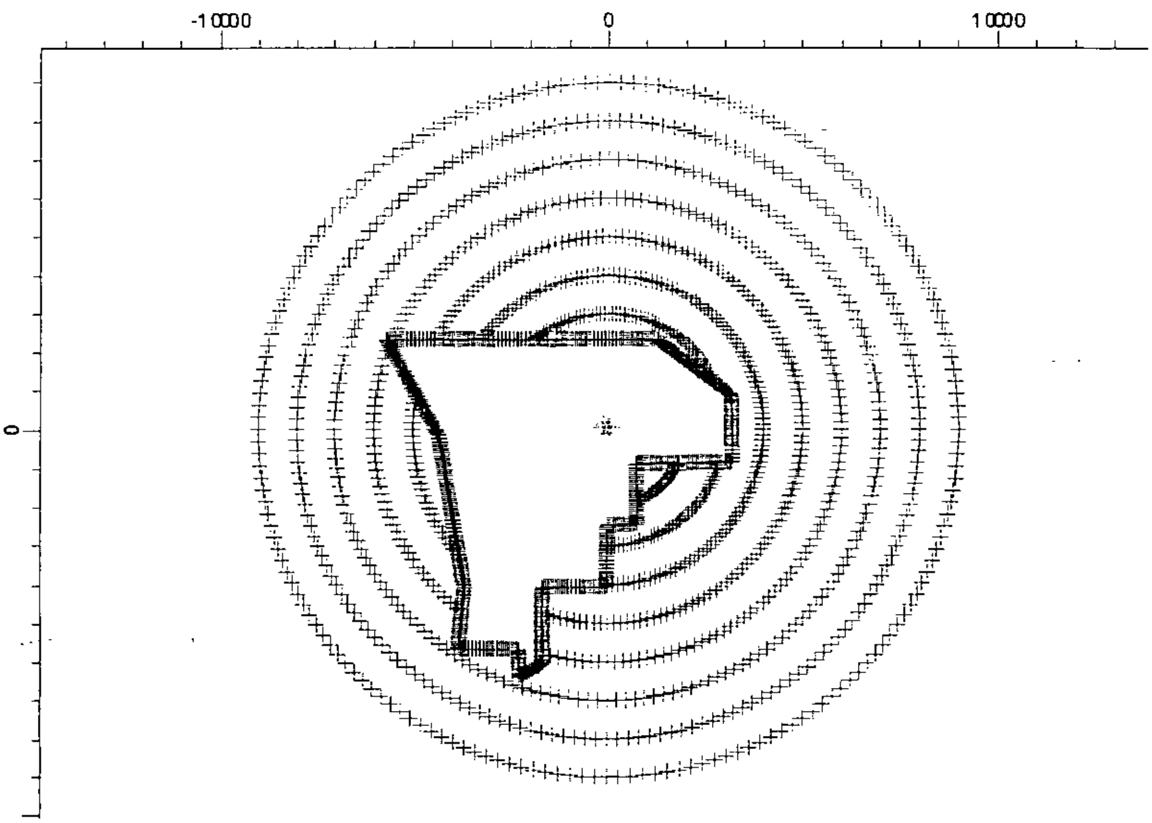


COMMENTS :	SOURCES :	COMPANY NAME :	
	36	**Golder Associates, Inc.**	
	RECEPTORS :	MODELER :	SCALE
	1737	**Larocca**	0 5 km
		DATE :	PROJECT NO :
		1/17/02	

**AAQS AND PSD CLASS II
INCREMENT RECEPTOR GRIDS**

PROJECT TITLE :

AAQS and PSD Class I Increment Analysis Grid



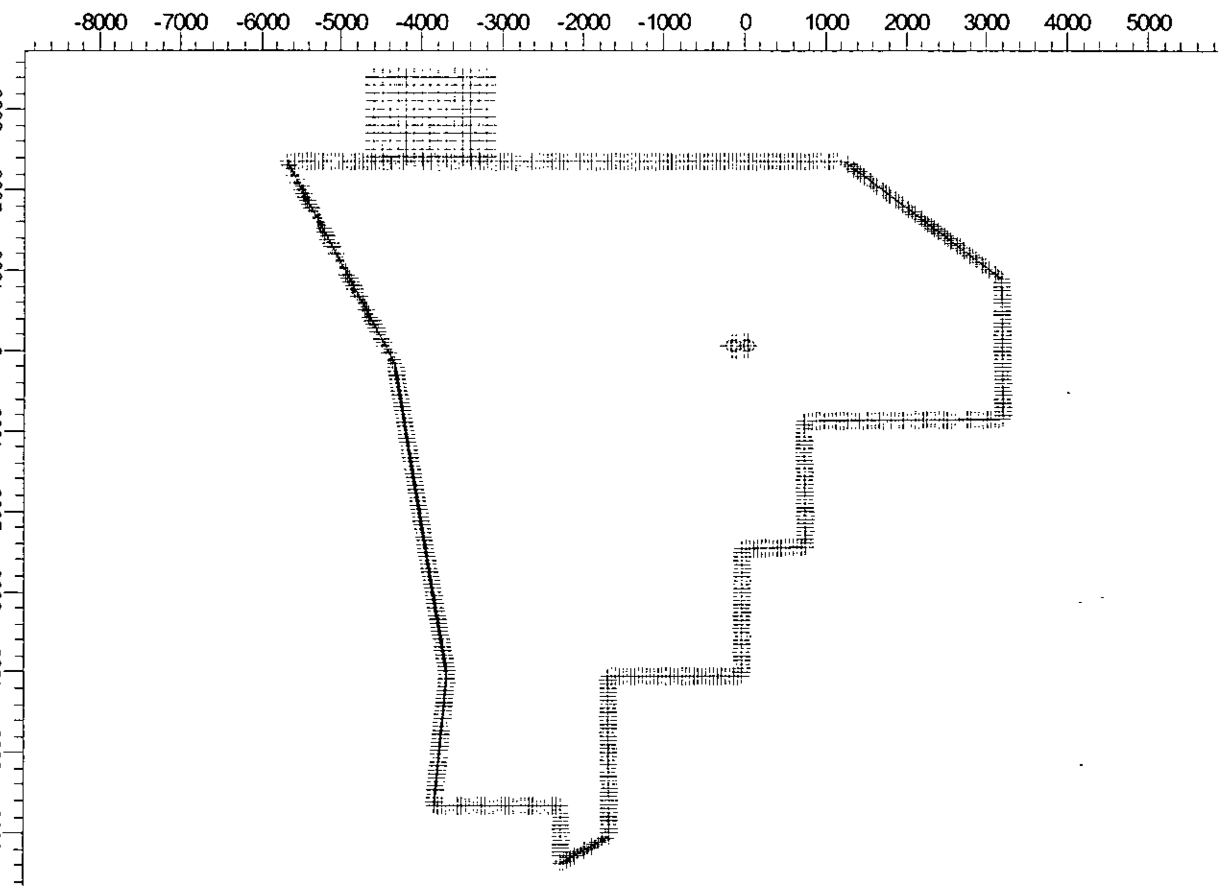
COMMENTS :	SOURCES : 36	COMPANY NAME Golder Associates, Inc.	
	RECEPTORS : 1750	MODELER Larocca	SCALE : 0 5 km
		DATE : 1/17/02	PROJECT NO. :

ISCAERMOD View - Lakes Environmental Software

D:\martin\iscst3\combined\AAQS\aaqs.isc

PROJECT TITLE :

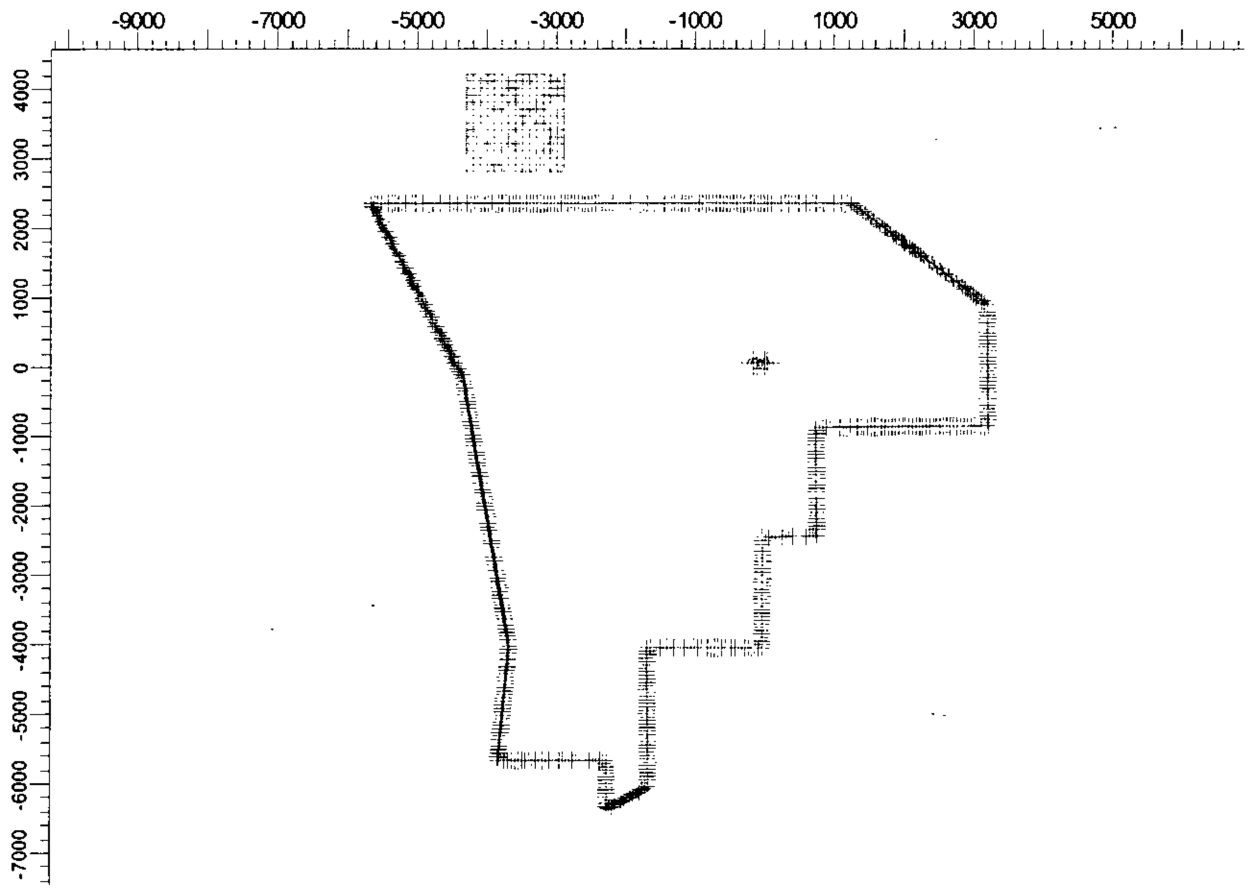
Refined AAQS Receptor Grid
1987 24-Hour SO2 Analysis



COMMENTS :	SOURCES : 36	COMPANY NAME : **Golder Associates, Inc.**	
	RECEPTORS : 822	MODELER : **Larocca**	SCALE : 0 2 km
		DATE : 1/24/02	PROJECT NO. :

PROJECT TITLE :

Refined AAQS Receptor Grid
1991 24-Hour SO2 Analysis



COMMENTS :	SOURCES :	COMPANY NAME :	
	36	Golder Associates, Inc.	
	RECEPTORS :	MODELER :	SCALE :
	882	Larocca	0 3 km
		DATE :	PROJECT NO. :
		1/24/02	

ISC-AERMOD View - Lakes Environmental Software

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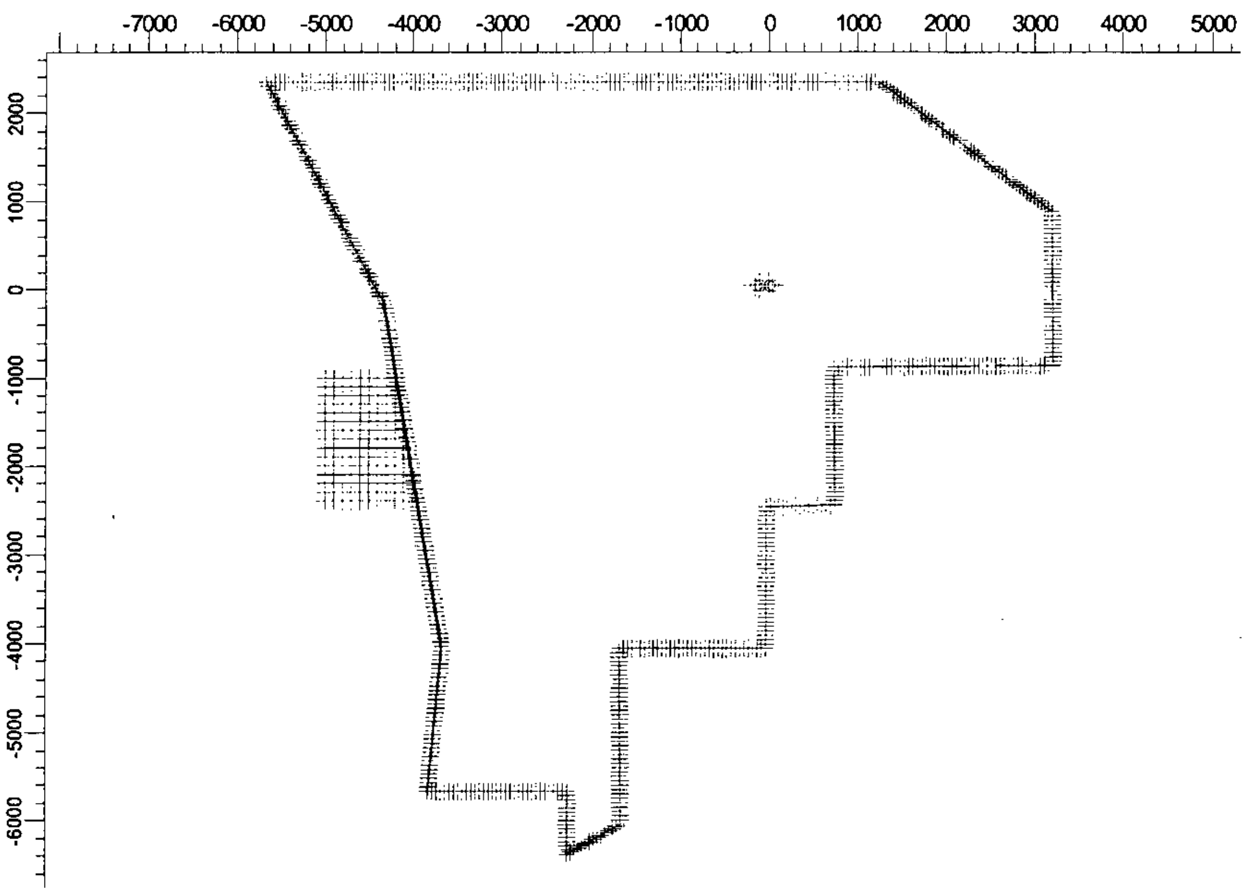
PROJECT TITLE :

Refined PSD Class II Increment Receptor Grid
1990 24-Hour SO2 Analysis



COMMENTS :	SOURCES : 36	COMPANY NAME : Golder Associates, Inc.	
	RECEPTORS : 805	MODELER : Larocca	SCALE : 0 — 2 km
		DATE : 1/24/02	PROJECT NO. :

ISC-AERMOD View - Lakes Environmental Software

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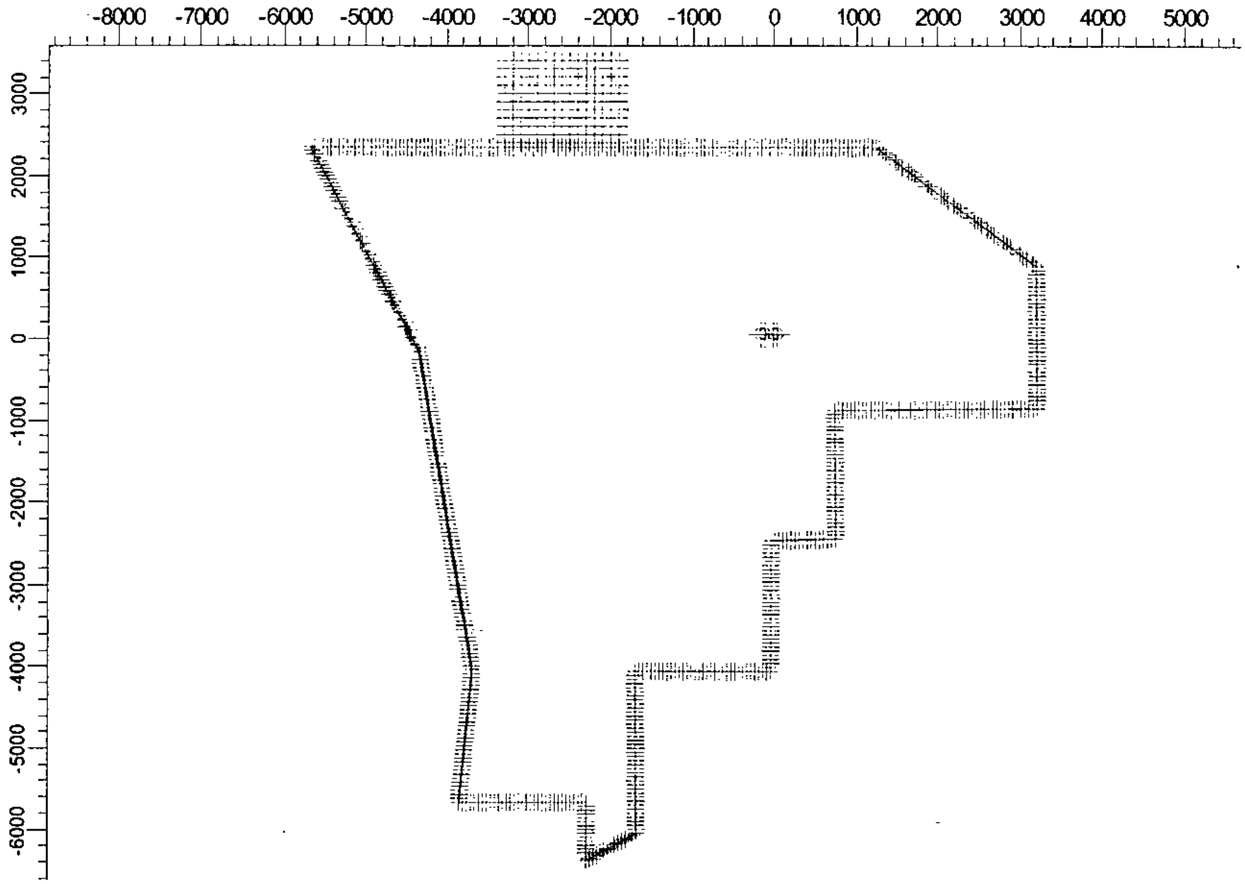
PROJECT TITLE :

Refined PSD Class II Receptor Grid
1987 24-Hour SO2 Analysis



COMMENTS :	SOURCES :	COMPANY NAME :	
	36	**Golder Associates, Inc.**	
	RECEPTORS :	MODELER :	SCALE :
	822	**Larocca**	0 ___ 2 km
		DATE :	PROJECT NO. :
		1/24/02	

ISC-AERMOD View - Lakes Environmental Software

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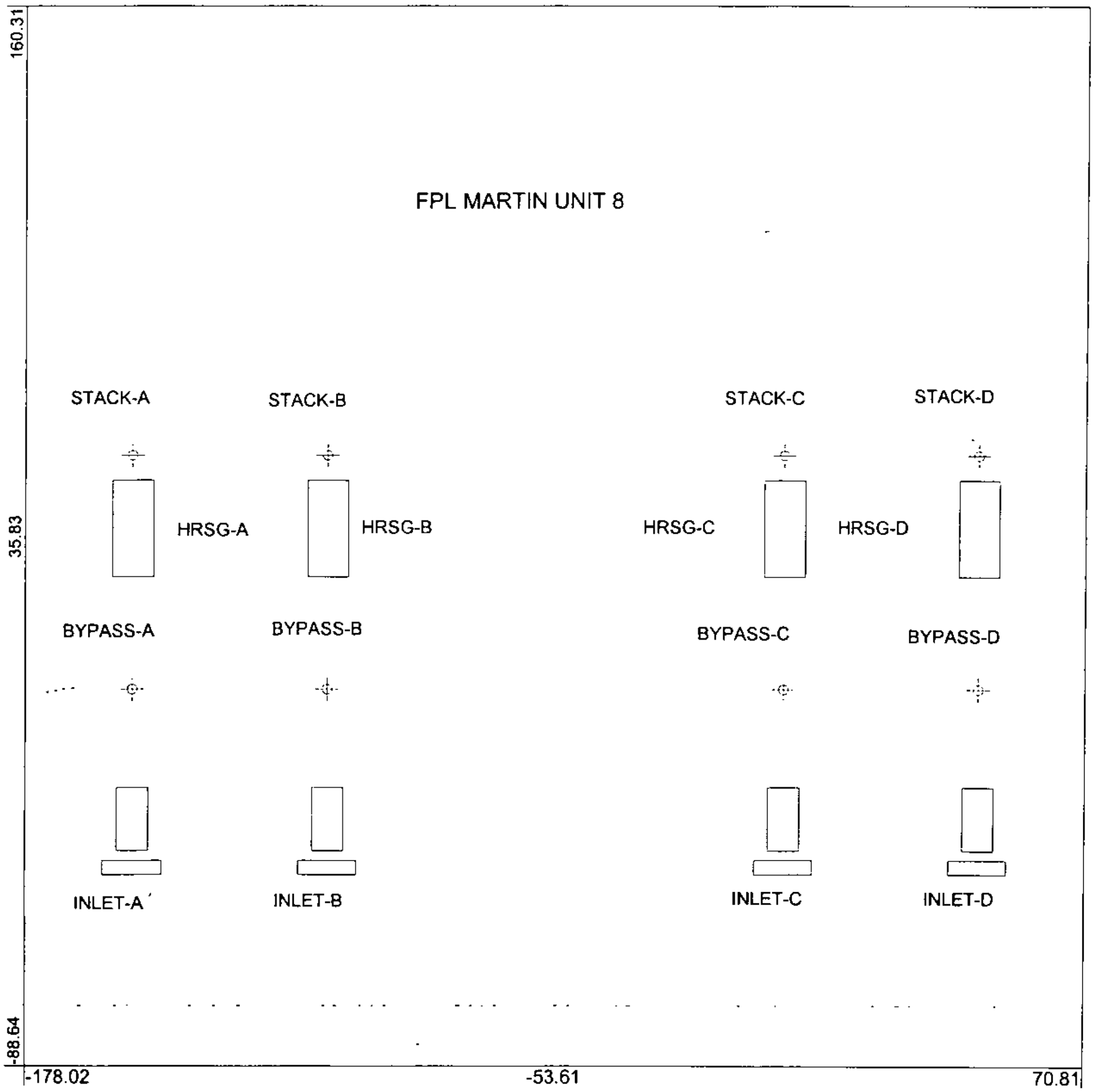
BUILDING PROFILE INPUT PROGRAM (BPIP) FILES

PROJECT NAME :

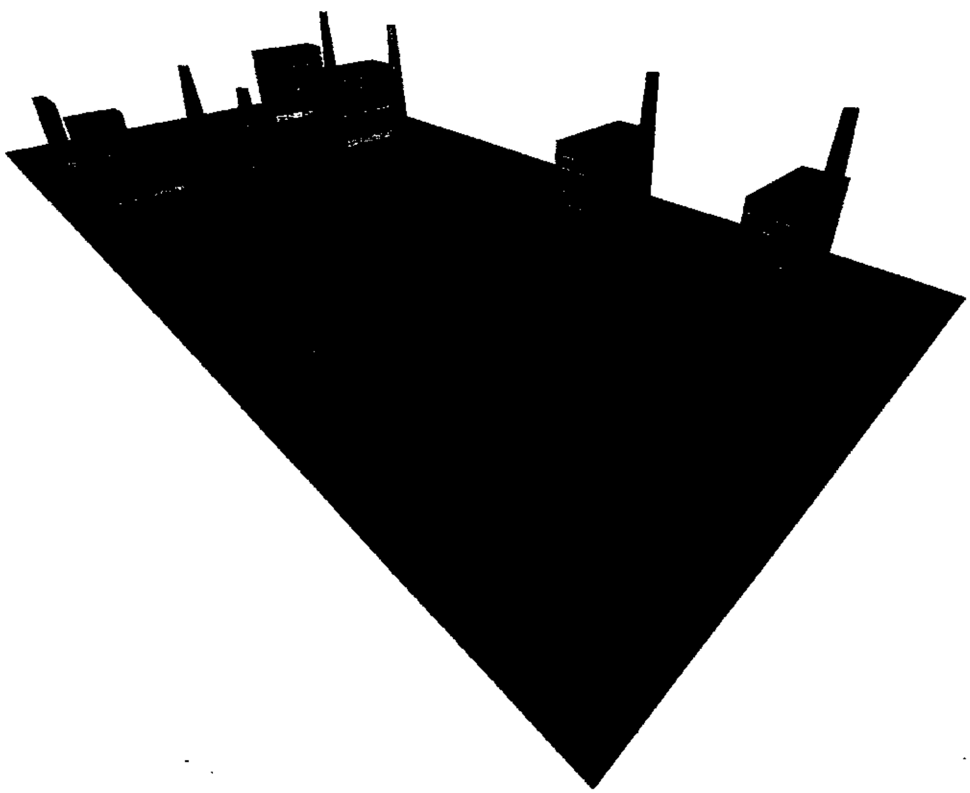
Building Structures Included in Downwash Analysis



COMMENTS :	BUILDINGS : **12**	COMPANY NAME : **Golder Associates, Inc.**	
	SOURCES : **8**	MODELER : **Larocca**	0 — 0.05 km
		DATE : **1/25/02**	PROJECT NO. :

TITLE:

BPIP 3D Image



COMMENTS:	STACKS: 8	COMPANY NAME: Golder Associates, Inc.	
	BUILDINGS: 12	MODELER: Larocca	PROJECT NO.: 0
		DATE: 1/17/02	

```
'D:\martin\bpip\martin3.bpv'
'ST'
'Meters'  1.00000000
'UTMN'  270.0000
12
'HRSG4'   1             0.000
    4          25.300
               49.210          157.430
               49.210          147.980
               26.510          147.980
               26.510          157.430
'HRSG2'   1             0.000
    4          25.300
               49.213          111.710
               49.213          102.260
               26.513          102.260
               26.510          111.710
'HRSG3'   1             0.000
    4          25.300
               49.213            4.572
               49.213           -4.880
               26.513           -4.880
               26.513            4.570
'HRSG4'   1             0.000
    4          25.300
               49.213          -41.148
               49.213          -50.598
               26.513          -50.600
               26.513          -41.148
'INLET3'   1             0.000
    4          20.270
              -40.044            6.851
              -40.044           -6.749
              -43.244           -6.749
              -43.240            6.851
'INLET4'   1             0.000
    4          20.270
              -40.044          -38.869
              -40.044          -52.469
              -43.244          -52.469
              -43.244          -38.869
'DUCT3'   1             0.000
    4          13.720
              -22.922            3.642
              -22.922           -3.658
              -37.642           -3.658
              -37.642            3.642
'DUCT4'   1             0.000
    4          13.720
              -22.922          -42.078
              -22.922          -49.378
              -37.642          -49.378
              -37.642          -42.078
'DUCT1'   1             0.000
    4          13.720
              -23.000          156.400
              -23.000          149.100
              -37.720          149.100
              -37.720          156.400
'DUCT2'   1             0.000
    4          13.720
              -23.000          110.690
              -23.000          103.390
              -37.720          103.390
              -37.720          110.690
'INLET1'   1             0.000
    4          20.270
              -40.140          159.500
              -40.140          145.900
              -43.340          145.900
              -43.340          159.500
'INLET2'   1             0.000
    4          20.270
              -40.140          113.780
```

```
               -40.140          100.180
               -43.340          100.180
               -43.340          113.780
8
'SC3'           0.000           24.384          0.000          0.000
'SC4'           0.000           24.384          0.000        -45.720
'CC1'           0.000           36.576         55.009        152.858
'CC2'           0.000           36.576         55.009        107.138
'CC3'           0.000           36.576         55.009          0.000
'CC4'           0.000           36.576         55.009        -45.720
'OLDSC1'          0.000           24.384          0.000          152.858
'OLDSC2'          0.000           24.384          0.000          107.138
```

BPIP (Dated: 95086)

DATE : 1/ 3/ 2
TIME : 13:10:12
D:\martin\bpip\martin3.bpv

==========================
BPIP PROCESSING INFORMATION:
==========================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in Meters will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

UTMP is set to UTMN. The input is assumed to be in a local X-Y coordinate system as opposed to a UTM coordinate system. True North is in the positive Y direction.

Plant north is set to 270.00 degrees with respect to True North.

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PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
SC3	24.38	0.00	62.19	65.00
SC4	24.38	0.00	62.02	65.00
CC1	36.58	0.00	62.19	65.00
CC2	36.58	0.00	62.18	65.00
CC3	36.58	0.00	62.18	65.00
CC4	36.58	0.00	62.18	65.00
OLDSC1	24.38	0.00	62.03	65.00
OLDSC2	24.38	0.00	62.18	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.
** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

DATE : 1/ 3/ 2
TIME : 13:10:12

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BPIP output is in meters

SO BUILDHGT SC3	25.30	25.30	25.30	0.00	0.00	0.00
SO BUILDHGT SC3	25.30	0.00	0.00	25.30	25.30	25.30
SO BUILDHGT SC3	0.00	0.00	25.30	25.30	25.30	25.30
SO BUILDHGT SC3	25.30	25.30	25.30	25.30	25.30	25.30

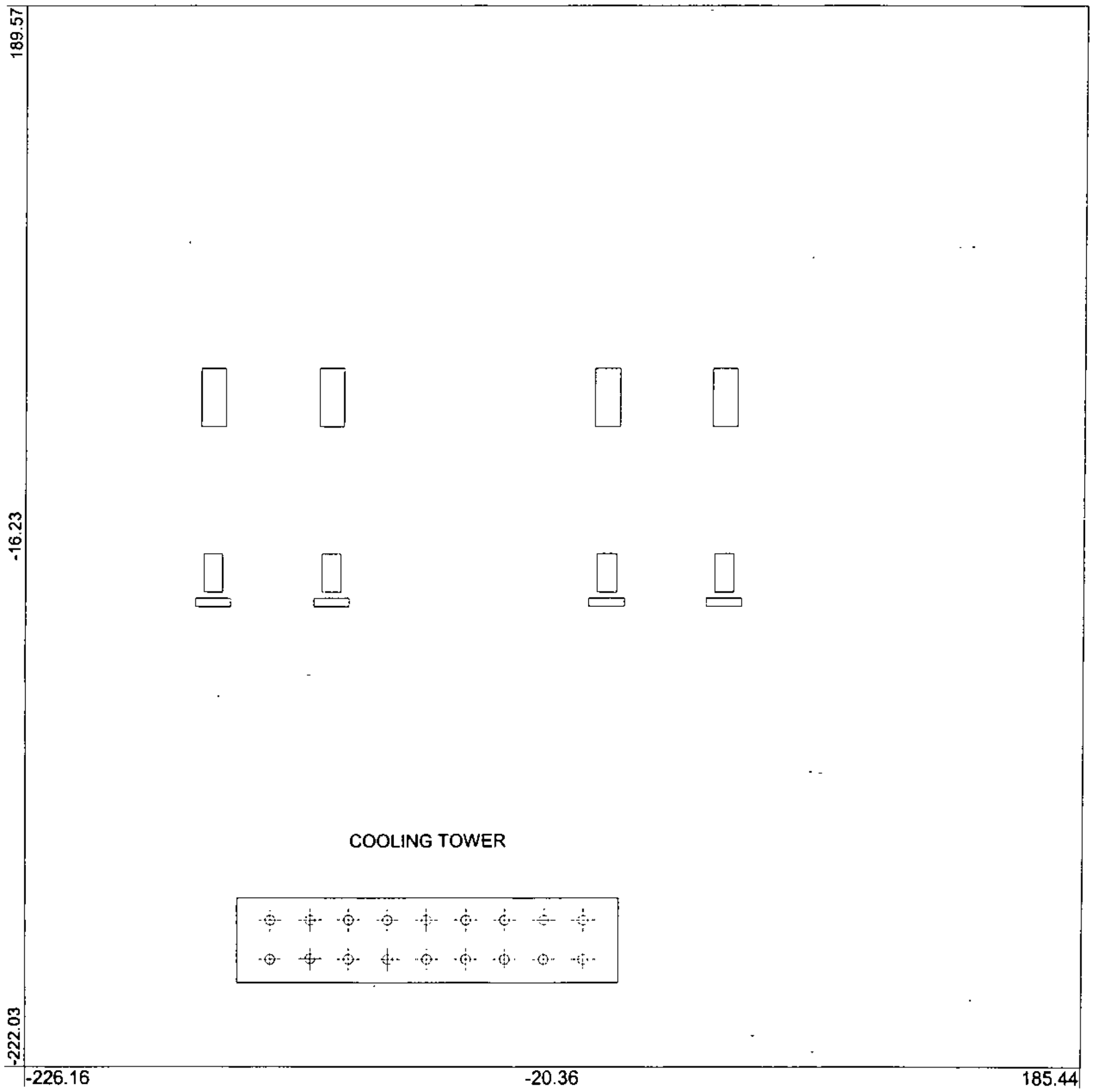
```
SO BUILDHGT SC3       25.30   0.00   0.00   0.00  13.72  13.72
SO BUILDHGT SC3       20.27  20.27  25.30  25.30  25.30  20.27
SO BUILDWID SC3       13.25  16.65  19.54   0.00   0.00   0.00
SO BUILDWID SC3       24.56   0.00   0.00  24.00  24.57  24.39
SO BUILDWID SC3        0.00   0.00  19.53  16.64  13.25   9.45
SO BUILDWID SC3       13.25  16.65  19.54  21.83  23.46  24.38
SO BUILDWID SC3       24.56   0.00   0.00   0.00  16.33  16.40
SO BUILDWID SC3       11.19  12.48  19.53  16.64  13.25  13.60

SO BUILDHGT SC4       25.30  25.30  25.30  20.27  20.27  13.72
SO BUILDHGT SC4       13.72   0.00   0.00   0.00  25.30  25.30
SO BUILDHGT SC4       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT SC4       25.30  25.30  25.30   0.00   0.00   0.00
SO BUILDHGT SC4        0.00   0.00   0.00   0.00  25.30  25.30
SO BUILDHGT SC4        0.00   0.00  25.30  25.30  25.30  20.27
SO BUILDWID SC4       13.25  16.65  19.54  12.48  11.19  16.40
SO BUILDWID SC4       16.33   0.00   0.00   0.00  24.48  24.38
SO BUILDWID SC4       23.46  21.83  19.53  16.64  13.25   9.45
SO BUILDWID SC4       13.25  16.65  19.54   0.00   0.00   0.00
SO BUILDWID SC4        0.00   0.00   0.00   0.00  24.48  24.38
SO BUILDWID SC4        0.00   0.00  19.53  16.64  13.25  13.60

SO BUILDHGT CC1       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC1       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC1       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC1       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC1       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC1       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDWID CC1       13.25  16.64  19.53  21.83  23.46  24.38
SO BUILDWID CC1       24.56  24.00  22.70  24.00  24.57  24.39
SO BUILDWID CC1       23.47  21.83  19.53  16.64  13.25   9.45
SO BUILDWID CC1       13.25  16.64  19.53  21.83  23.46  24.38
SO BUILDWID CC1       24.56  24.00  22.70  24.00  24.57  24.39
SO BUILDWID CC1       23.47  21.83  19.53  16.64  13.25   9.45

SO BUILDHGT CC2       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC2       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC2       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC2       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC2       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC2       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDWID CC2       13.25  16.64  19.53  21.83  23.46  24.38
SO BUILDWID CC2       24.56  24.00  22.70  24.00  24.57  24.39
SO BUILDWID CC2       23.47  21.83  19.54  16.64  13.25   9.45
SO BUILDWID CC2       13.25  16.64  19.53  21.83  23.46  24.38
SO BUILDWID CC2       24.56  24.00  22.70  24.00  24.57  24.39
SO BUILDWID CC2       23.47  21.83  19.54  16.64  13.25   9.45

SO BUILDHGT CC3       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC3       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC3       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC3       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC3       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC3       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDWID CC3       13.25  16.65  19.54  21.83  23.46  24.38
SO BUILDWID CC3       24.56  24.00  22.70  24.00  24.56  24.38
SO BUILDWID CC3       23.46  21.83  19.53  16.64  13.25   9.45
SO BUILDWID CC3       13.25  16.65  19.54  21.83  23.46  24.38
SO BUILDWID CC3       24.56  24.00  22.70  24.00  24.56  24.38
SO BUILDWID CC3       23.46  21.83  19.53  16.64  13.25   9.45

SO BUILDHGT CC4       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC4       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC4       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC4       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC4       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDHGT CC4       25.30  25.30  25.30  25.30  25.30  25.30
SO BUILDWID CC4       13.25  16.65  19.54  21.83  23.46  24.38
SO BUILDWID CC4       24.56  24.00  22.70  24.00  24.56  24.38
```

```
SO BUILDWID CC4        23.46   21.83   19.53   16.64   13.25    9.45
SO BUILDWID CC4        13.25   16.65   19.54   21.83   23.46   24.38
SO BUILDWID CC4        24.56   24.00   22.70   24.00   24.56   24.38
SO BUILDWID CC4        23.46   21.83   19.53   16.64   13.25    9.45

SO BUILDHGT OLDSC1     25.30   25.30   25.30    0.00    0.00    0.00
SO BUILDHGT OLDSC1     25.30    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT OLDSC1      0.00    0.00   25.30   25.30   25.30   25.30
SO BUILDHGT OLDSC1     25.30   25.30   25.30   25.30   25.30   25.30
SO BUILDHGT OLDSC1     25.30    0.00    0.00    0.00   13.72   13.72
SO BUILDHGT OLDSC1     20.27   20.27   25.30   25.30   25.30   20.27
SO BUILDWID OLDSC1     13.25   16.64   19.53    0.00    0.00    0.00
SO BUILDWID OLDSC1     24.49    0.00    0.00    0.00    0.00    0.00
SO BUILDWID OLDSC1      0.00    0.00   19.53   16.64   13.25    9.45
SO BUILDWID OLDSC1     13.25   16.64   19.53   21.83   23.46   24.38
SO BUILDWID OLDSC1     24.49    0.00    0.00    0.00   16.33   16.40
SO BUILDWID OLDSC1     11.19   12.48   19.53   16.64   13.25   13.60

SO BUILDHGT OLDSC2     25.30   25.30   25.30   20.27   20.27   13.72
SO BUILDHGT OLDSC2     13.72    0.00    0.00    0.00   25.30   25.30
SO BUILDHGT OLDSC2     25.30   25.30   25.30   25.30   25.30   25.30
SO BUILDHGT OLDSC2     25.30   25.30   25.30    0.00    0.00   25.30
SO BUILDHGT OLDSC2     25.30   25.30    0.00    0.00   25.30   25.30
SO BUILDHGT OLDSC2      0.00    0.00   25.30   25.30   25.30   20.27
SO BUILDWID OLDSC2     13.25   16.64   19.53   12.48   11.19   16.40
SO BUILDWID OLDSC2     16.33    0.00    0.00    0.00   24.56   24.38
SO BUILDWID OLDSC2     23.46   21.83   19.54   16.64   13.25    9.45
SO BUILDWID OLDSC2     13.25   16.64   19.53    0.00    0.00   24.38
SO BUILDWID OLDSC2     24.56   24.00    0.00    0.00   24.56   24.38
SO BUILDWID OLDSC2      0.00    0.00   19.54   16.64   13.25   13.60
```

COOLING TOWER

PROJECT NAME :

Building Structures Included in Cooling Tower Downwash Analysis



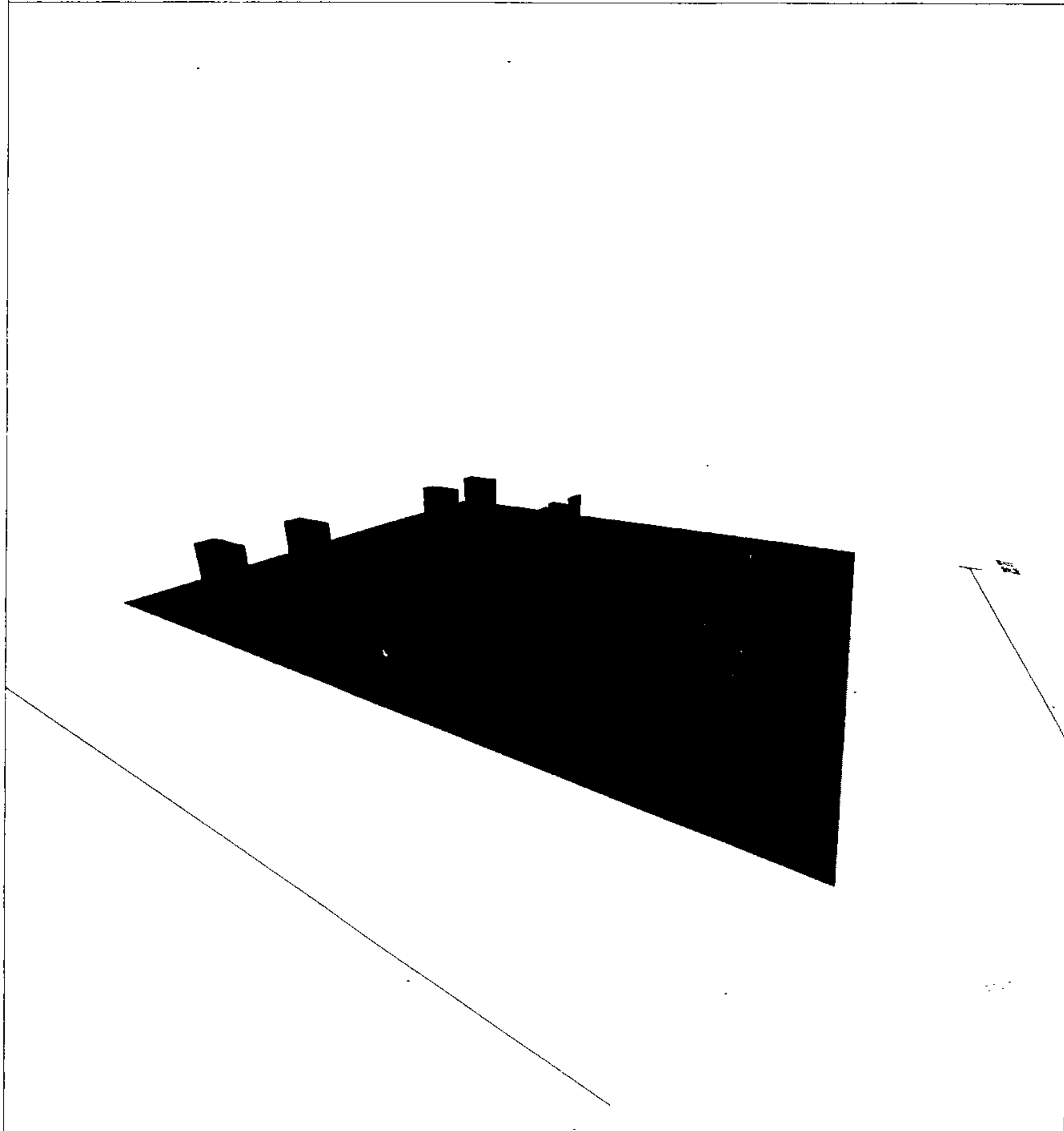
COMMENTS :	BUILDINGS : **13**	COMPANY NAME : **Golder Associates, Inc.**
	SOURCES : **18**	MODELER : **Larocca** / 0 — 0.05 km
		DATE : **1/25/02** / PROJECT NO. :

BPIP View by Lakes Environmental Software

D:\martin\bpip\cool.bpv

TITLE.

BPIP 3D Image



COMMENTS:	STACKS: 18	COMPANY NAME: Golder Associates, Inc.	
	BUILDINGS: 13	MODELER: Larocca	PROJECT NO.: 0
		DATE: 1/22/02	

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'D:\manatee\bpip\cool.bpv'
'ST'
'Meters'  1.00000000
'UTMN'  0.0000
13
'BLDG1'   1             0.000
    4          12.190
             -143.060          -156.690
                5.000          -156.690
                5.000          -189.570
             -143.060          -189.570
'HRSGA'   1             0.000
    4          25.300
             -157.440            49.170
             -147.840            49.170
             -147.840            26.420
             -157.440            26.420
'HRSGB'   1             0.000
    4          25.300
             -111.750            49.170
             -102.150            49.170
             -102.150            26.420
             -111.750            26.420
'HRSGC'   1             0.000
    4          25.300
               -4.600            49.170
                5.000            49.170
                5.000            26.420
               -4.600            26.420
'HRSGD'   1             0.000
    4          25.300
               41.190            49.170
               50.680            49.170
               50.680            26.420
               41.190            26.420
'INLETA'   1             0.000
    4          20.270
             -159.640           -40.150
             -145.890           -40.150
             -145.890           -43.450
             -159.640           -43.450
'INLETB'   1             0.000
    4          20.270
             -113.920           -40.150
             -100.170           -40.150
             -100.170           -43.450
             -113.920           -43.450
'INLETC'   1             0.000
    4          20.270
               -6.860           -40.060
                6.800           -40.060
                6.800           -43.360
               -6.860           -43.360
'INLETD'   1             0.000
    4          20.270
               38.900           -40.060
               52.550           -40.060
               52.550           -43.360
               38.900           -43.360
'DUCTA'   1             0.000
    4          13.720
             -156.370           -23.050
             -149.030           -23.050
             -149.030           -37.820
             -156.370           -37.820
'DUCTB'   1             0.000
    4          13.720
             -110.650           -23.050
             -103.310           -23.050
             -103.310           -37.820
             -110.650           -37.820
'DUCTC'   1             0.000
    4          13.720
               -3.650           -22.950
```

```
                3.780          -22.950
                3.780          -37.820
               -3.650          -37.820
'DUCTD'    1          0.000
    4          13.720
               42.100          -22.950
               49.440          -22.950
               49.440          -37.820
               42.100          -37.820
18
'CELL01'          0.000          13.716        -130.330        -165.320
'CELL02'          0.000          13.716        -114.950        -165.320
'CELL03'          0.000          13.716         -99.940        -165.320
'CELL04'          0.000          13.716         -84.770        -165.320
'CELL05'          0.000          13.716         -69.600        -165.320
'CELL06'          0.000          13.716         -54.210        -165.320
'CELL07'          0.000          13.716         -39.040        -165.320
'CELL08'          0.000          13.716         -23.600        -165.320
'CELL09'          0.000          13.716          -8.430        -165.320
'CELL10'          0.000          13.716        -130.330        -180.550
'CELL11'          0.000          13.716        -114.950        -180.330
'CELL12'          0.000          13.716         -99.940        -180.550
'CELL13'          0.000          13.716         -84.550        -180.550
'CELL14'          0.000          13.716         -69.380        -180.550
'CELL15'          0.000          13.716         -54.210        -180.550
'CELL16'          0.000          13.716         -39.040        -180.550
'CELL17'          0.000          13.716         -23.820        -180.550
'CELL18'          0.000          13.716          -8.430        -180.550
```

BPIP (Dated: 95086)

DATE : 1/23/ 2
TIME : 9:35:33
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===========================
BPIP PROCESSING INFORMATION:
===========================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in Meters will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

UTMP is set to UTMN. The input is assumed to be in a local X-Y coordinate system as opposed to a UTM coordinate system. True North is in the positive Y direction.

Plant north is set to 0.00 degrees with respect to True North.

D:\manatee\bpip\cool.bpv

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
CELL01	13.72	0.00	30.47	65.00
CELL02	13.72	0.00	30.47	65.00
CELL03	13.72	0.00	30.47	65.00
CELL04	13.72	0.00	30.47	65.00
CELL05	13.72	0.00	30.47	65.00
CELL06	13.72	0.00	30.47	65.00
CELL07	13.72	0.00	30.47	65.00
CELL08	13.72	0.00	30.47	65.00
CELL09	13.72	0.00	30.47	65.00
CELL10	13.72	0.00	30.47	65.00
CELL11	13.72	0.00	30.47	65.00
CELL12	13.72	0.00	30.47	65.00
CELL13	13.72	0.00	30.47	65.00
CELL14	13.72	0.00	30.47	65.00
CELL15	13.72	0.00	30.47	65.00
CELL16	13.72	0.00	30.47	65.00
CELL17	13.72	0.00	30.47	65.00
CELL18	13.72	0.00	30.47	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

DATE : 1/23/ 2
TIME : 9:35:33

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BPIP output is in meters

```
SO BUILDHGT CELL01    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL01    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL01    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL01    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL01    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL01    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL01   151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL01    81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL01   120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL01   151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL01    81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL01   120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL02    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL02    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL02    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL02    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL02    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL02    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL02   151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL02    81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL02   120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL02   151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL02    81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL02   120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL03    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL03    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL03    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL03    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL03    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL03    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL03   151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL03    81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL03   120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL03   151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL03    81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL03   120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL04    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL04    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL04    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL04    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL04    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL04    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL04   151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL04    81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL04   120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL04   151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL04    81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL04   120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL05    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL05    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL05    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL05    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL05    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL05    12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL05   151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL05    81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL05   120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL05   151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL05    81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL05   120.36  134.56  144.66  150.38  151.52  148.06
```

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SO BUILDHGT CELL06     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL06     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL06     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL06     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL06     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL06     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL06    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL06     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL06    120.36   134.56   144.66   150.38   151.52   148.06
SO BUILDWID CELL06    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL06     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL06    120.36   134.56   144.66   150.38   151.52   148.06

SO BUILDHGT CELL07     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL07     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL07     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL07     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL07     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL07     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL07    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL07     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL07    120.36   134.56   144.66   150.38   151.52   148.06
SO BUILDWID CELL07    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL07     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL07    120.36   134.56   144.66   150.38   151.52   148.06

SO BUILDHGT CELL08     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL08     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL08     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL08     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL08     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL08     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL08    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL08     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL08    120.36   134.56   144.66   150.38   151.52   148.06
SO BUILDWID CELL08    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL08     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL08    120.36   134.56   144.66   150.38   151.52   148.06

SO BUILDHGT CELL09     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL09     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL09     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL09     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL09     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL09     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL09    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL09     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL09    120.36   134.56   144.66   150.38   151.52   148.06
SO BUILDWID CELL09    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL09     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL09    120.36   134.56   144.66   150.38   151.52   148.06

SO BUILDHGT CELL10     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL10     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL10     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL10     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL10     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL10     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDWID CELL10    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL10     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL10    120.36   134.56   144.66   150.38   151.52   148.06
SO BUILDWID CELL10    151.52   150.38   144.66   134.56   120.36   102.50
SO BUILDWID CELL10     81.54    58.09    32.88    58.09    81.54   102.50
SO BUILDWID CELL10    120.36   134.56   144.66   150.38   151.52   148.06

SO BUILDHGT CELL11     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL11     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL11     12.19    12.19    12.19    12.19    12.19    12.19
SO BUILDHGT CELL11     12.19    12.19    12.19    12.19    12.19    12.19
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   SO BUILDHGT CELL11      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL11      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDWID CELL11     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL11      81.54    58.09    32.88    58.09    81.54   102.50
   SO BUILDWID CELL11     120.36   134.56   144.66   150.38   151.52   148.06
   SO BUILDWID CELL11     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL11      81.54    58.09    32.88    58.09    81.54   102.50
   SO BUILDWID CELL11     120.36   134.56   144.66   150.38   151.52   148.06

   SO BUILDHGT CELL12      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL12      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL12      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL12      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL12      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL12      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDWID CELL12     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL12      81.54    58.09    32.88    58.09    81.54   102.50
   SO BUILDWID CELL12     120.36   134.56   144.66   150.38   151.52   148.06
   SO BUILDWID CELL12     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL12      81.54    58.09    32.88    58.09    81.54   102.50
   SO BUILDWID CELL12     120.36   134.56   144.66   150.38   151.52   148.06

   SO BUILDHGT CELL13      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL13      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL13      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL13      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL13      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL13      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDWID CELL13     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL13      81.54    58.09    32.88    58.09    81.54   102.50
   SO BUILDWID CELL13     120.36   134.56   144.66   150.38   151.52   148.06
   SO BUILDWID CELL13     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL13      81.54    58.09    32.88    58.09    81.54   102.50
   SO BUILDWID CELL13     120.36   134.56   144.66   150.38   151.52   148.06

   SO BUILDHGT CELL14      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL14      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL14      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL14      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL14      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL14      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDWID CELL14     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL14      81.54    58.09    32.88    58.09    81.54   102.50
   SO BUILDWID CELL14     120.36   134.56   144.66   150.38   151.52   148.06
   SO BUILDWID CELL14     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL14      81.54    58.09    32.88    58.09    81.54   102.50
   SO BUILDWID CELL14     120.36   134.56   144.66   150.38   151.52   148.06

   SO BUILDHGT CELL15      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL15      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL15      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL15      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL15      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL15      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDWID CELL15     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL15      81.54    58.09    32.88    58.09    81.54   102.50
   SO BUILDWID CELL15     120.36   134.56   144.66   150.38   151.52   148.06
   SO BUILDWID CELL15     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL15      81.54    58.09    32.88    58.09    81.54   102.50
   SO BUILDWID CELL15     120.36   134.56   144.66   150.38   151.52   148.06

   SO BUILDHGT CELL16      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL16      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL16      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL16      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL16      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDHGT CELL16      12.19    12.19    12.19    12.19    12.19    12.19
   SO BUILDWID CELL16     151.52   150.38   144.66   134.56   120.36   102.50
   SO BUILDWID CELL16      81.54    58.09    32.88    58.09    81.54   102.50
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SO BUILDWID CELL16    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL16    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL16     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL16    120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL17     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL17    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL17     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL17    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL17    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL17     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL17    120.36  134.56  144.66  150.38  151.52  148.06

SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDHGT CELL18     12.19   12.19   12.19   12.19   12.19   12.19
SO BUILDWID CELL18    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL18     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL18    120.36  134.56  144.66  150.38  151.52  148.06
SO BUILDWID CELL18    151.52  150.38  144.66  134.56  120.36  102.50
SO BUILDWID CELL18     81.54   58.09   32.88   58.09   81.54  102.50
SO BUILDWID CELL18    120.36  134.56  144.66  150.38  151.52  148.06
```

APPENDIX F

MODEL SUMMARY AND INPUT FILES

SIMPLE CYCLE LOAD ANALYSIS
ISCST3 SUMMARY

Table F-1. Maximum Pollutant Concentrations Predicted for One Combustion Turbine in Simple Cycle Operation

Pollutant	Maximum Emission Rates (lb/hr) by Operating Load and Air Inlet Temperature: Power Augmentation	Higher Power Mode	Baseload			75% Load			50% Load			Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Inlet Temperature[a]: Power Augmentation	Higher Power Mode	Baseload			75% Load			50% Load		
	80°F	95°F	95°F	59°F	35°F	95°F	59°F	35°F	95°F	59°F	35°F		80°F	95oF	95°F	59°F	35°F	95°F	59°F	35°F	95°F	59°F	35°F
Natural Gas																							
Generic (9 g/s)	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	71.43	Annual	0.013	0.013	0.014	0.013	0.013	0.017	0.016	0.016	0.019	0.019	0.019
												1-Hour	1.278	1.275	1.288	1.275	1.173	2.132	2.121	2.117	2.176	2.172	2.169
												3-Hour	0.776	0.768	0.802	0.766	0.749	0.915	0.904	0.893	1.019	1.010	1.003
												8-Hour	0.428	0.428	0.440	0.428	0.427	0.526	0.508	0.500	0.597	0.590	0.585
												24-Hour	0.174	0.172	0.182	0.171	0.169	0.222	0.213	0.209	0.255	0.252	0.249
SO_2	9.5	9.6	8.9	9.8	10.2	7.3	7.9	8.25	5.9	6.4	6.6	Annual	0.0018	0.0018	0.0018	0.0018	0.0019	0.0017	0.0018	0.0019	0.0016	0.0017	0.0017
												24-Hour	0.023	0.0232	0.0226	0.0235	0.0243	0.0226	0.0236	0.0241	0.0210	0.0225	0.0230
												3-Hour	0.10	0.1034	0.0995	0.1051	0.1074	0.0934	0.1006	0.1031	0.0839	0.0905	0.0926
PM_{10}	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	Annual	0.0017	0.0017	0.0018	0.0017	0.0016	0.0021	0.0021	0.0020	0.0024	0.0024	0.0024
												24-Hour	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
NO_x/ NO_2	76.2	95.5	53.1	58.7	61.3	43.1	47.1	48.9	34.5	37.5	38.7	Annual	0.014	0.018	0.011	0.011	0.011	0.010	0.011	0.011	0.009	0.010	0.010
CO	45.0	44.7	25.5	27.5	28.6	21.7	23.5	24.4	18.3	19.5	20.1	8-Hour	0.27	0.27	0.16	0.16	0.17	0.16	0.17	0.17	0.15	0.16	0.16
												1-Hour	0.80	0.80	0.46	0.49	0.47	0.65	0.70	0.72	0.56	0.59	0.61
Fuel Oil																							
Generic (10 g/s)	N/A	N/A	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	N/A	N/A	0.015	0.014	0.014	0.018	0.017	0.017	0.021	0.020	0.020
												1-Hour	N/A	N/A	1.375	1.302	1.270	1.754	1.607	1.589	1.936	1.888	1.871
												3-Hour	N/A	N/A	0.870	0.832	0.814	0.995	0.988	0.980	1.118	1.096	1.089
												8-Hour	N/A	N/A	0.442	0.423	0.415	0.514	0.500	0.496	0.594	0.581	0.577
												24-Hour	N/A	N/A	0.174	0.166	0.162	0.211	0.199	0.196	0.263	0.253	0.250
SO_2	N/A	N/A	89.1	98.6	103.1	72.2	78.8	82.0	57.7	62.6	64.7	Annual	N/A	N/A	0.0167	0.0173	0.0177	0.0164	0.0173	0.0178	0.0154	0.0161	0.0165
												24-Hour	N/A	N/A	0.195	0.206	0.211	0.192	0.198	0.202	0.191	0.200	0.204
												3-Hour	N/A	N/A	0.98	1.03	1.06	0.90	0.98	1.01	0.81	0.86	0.89
PM_{10}	N/A	N/A	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	Annual	N/A	N/A	0.0032	0.0030	0.0029	0.0039	0.0037	0.0037	0.0045	0.0044	0.0043
												24-Hour	N/A	N/A	0.04	0.04	0.03	0.05	0.04	0.04	0.06	0.05	0.05
NO_x/ NO_2	N/A	N/A	288.2	319.2	333.8	231.2	252.6	262.6	183.2	198.9	205.6	Annual	N/A	N/A	0.054	0.056	0.057	0.052	0.055	0.057	0.049	0.051	0.053
CO	N/A	N/A	58.9	64.7	68.1	48.3	51.7	53.5	41.0	43.2	44.3	8-Hour	N/A	N/A	0.33	0.34	0.36	0.31	0.33	0.33	0.31	0.32	0.32
												1-Hour	N/A	N/A	1.0	1.1	1.1	1.1	1.0	1.1	1.0	1.0	1.0

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s

SIMPLE CYCLE
NATURAL GAS
SUMMARY FILE

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ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :SIMPLE.087
ISCST3 OUTPUT FILE NUMBER 2 :SIMPLE.088
ISCST3 OUTPUT FILE NUMBER 3 :SIMPLE.089
ISCST3 OUTPUT FILE NUMBER 4 :SIMPLE.090
ISCST3 OUTPUT FILE NUMBER 5 :SIMPLE.091
First title for last output file is: FPL MARTIN PROPOSED SIMPLE CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, N

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: BASE35					
Annual					
	1987	0.01063	-7880.1	6156.6	87123124
	1988	0.01081	-17658.9	9389.4	88123124
	1989	0.01292	-7193.4	6946.6	89123124
	1990	0.01137	-17320.5	10000.0	90123124
	1991	0.01252	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.13579	2309.0	1542.6	87081113
	1988	1.14432	-4921.8	937.3	88080411
	1989	1.13341	-4750.0	0.0	89041311
	1990	1.16558	2348.7	1512.9	90082313
	1991	1.17263	1785.4	2285.2	91071217
HIGH 3-Hour					
	1987	0.73268	-15760.2	12313.2	87060503
	1988	0.74148	1663.3	7825.2	88060815
	1989	0.70923	-19805.4	2783.5	89091103
	1990	0.70977	-20000.0	0.0	90031003
	1991	0.74895	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.36114	-3747.5	-4922.0	87053016
	1988	0.40529	-19562.9	-4158.2	88091624
	1989	0.40320	11183.9	-16580.8	89021108
	1990	0.42661	-5624.4	1195.5	90081616
	1991	0.38116	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.15596	14386.8	-13893.2	87120524
	1988	0.16272	-19696.2	3473.0	88091724
	1989	0.15069	-13382.6	14862.9	89031524
	1990	0.16948	-5624.4	1195.5	90081624
	1991	0.14936	-15320.9	12855.8	91032724
SOURCE GROUP ID: BASE59					
Annual					
	1987	0.01089	-7880.1	6156.6	87123124
	1988	0.01115	-17658.9	9389.4	88123124
	1989	0.01326	-7193.4	6946.6	89123124
	1990	0.01177	-17320.5	10000.0	90123124
	1991	0.01294	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.14226	2309.0	1542.6	87081113
	1988	1.16092	-4581.3	2343.7	88071112
	1989	1.13405	-4750.0	0.0	89041311
	1990	1.27483	-1846.3	2343.7	90082412
	1991	1.20484	1723.8	2206.4	91071217
HIGH 3-Hour					
	1987	0.74940	-15760.2	12313.2	87060503
	1988	0.75107	-15760.2	12313.2	88091003
	1989	0.72423	-19805.4	2783.5	89091103
	1990	0.72466	-20000.0	0.0	90031003
	1991	0.76635	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.36902	-15760.2	12313.2	87060508
	1988	0.41622	-19562.9	-4158.2	88091624
	1989	0.41297	11183.9	-16580.8	89021108
	1990	0.42776	-5624.4	1195.5	90081616
	1991	0.38960	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.16048	14386.8	-13893.2	87120524
	1988	0.16649	-19696.2	3473.0	88091724
	1989	0.15569	-13382.6	14862.9	89031524

	1990	0.17104	-16961.0	10598.4	90051524
	1991	0.15291	-15320.9	12855.8	91032724
SOURCE GROUP ID:	BASE95				
Annual					
	1987	0.01146	-7880.1	6156.6	87123124
	1988	0.01191	-13244.2	7042.1	88123124
	1989	0.01421	-7193.4	6946.6	89123124
	1990	0.01259	-17320.5	10000.0	90123124
	1991	0.01378	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.17775	3194.9	-57.4	87071513
	1988	1.21178	-5110.1	1288.9	88072412
	1989	1.13637	-4352.5	-2935.8	89081211
	1990	1.28844	-1846.3	2343.7	90082412
	1991	1.27346	1723.8	2206.4	91071217
HIGH 3-Hour					
	1987	0.78424	-15760.2	12313.2	87060503
	1988	0.78679	-15760.2	12313.2	88091003
	1989	0.75538	-19805.4	2783.5	89091103
	1990	0.75549	-20000.0	0.0	90031003
	1991	0.80247	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.38627	-15760.2	12313.2	87060508
	1988	0.44022	-19562.9	-4158.2	88091624
	1989	0.40198	11183.9	-16580.8	89021108
	1990	0.43084	-5379.8	1143.5	90081616
	1991	0.40718	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.17017	14386.8	-13893.2	87120524
	1988	0.17437	-19696.2	3473.0	88091724
	1989	0.16417	-13382.6	14862.9	89031524
	1990	0.18193	-16961.0	10598.4	90051524
	1991	0.16031	-15320.9	12855.8	91032724
SOURCE GROUP ID:	POWAUG				
Annual					
	1987	0.01103	-7880.1	6156.6	87123124
	1988	0.01136	-17658.9	9389.4	88123124
	1989	0.01346	-7193.4	6946.6	89123124
	1990	0.01203	-17320.5	10000.0	90123124
	1991	0.01312	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.14566	2309.0	1542.6	87081113
	1988	1.16133	-4581.3	2343.7	88071112
	1989	1.13451	-4750.0	0.0	89041311
	1990	1.27840	-1846.3	2343.7	90082412
	1991	1.22276	1723.8	2206.4	91071217
HIGH 3-Hour					
	1987	0.75837	-15760.2	12313.2	87060503
	1988	0.76025	-15760.2	12313.2	88091003
	1989	0.73226	-19805.4	2783.5	89091103
	1990	0.73262	-20000.0	0.0	90031003
	1991	0.77567	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.37346	-15760.2	12313.2	87060508
	1988	0.42219	-19562.9	-4158.2	88091624
	1989	0.41820	11183.9	-16580.8	89021108
	1990	0.42846	-5379.8	1143.5	90081616
	1991	0.39412	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.16291	14386.8	-13893.2	87120524
	1988	0.16851	-19696.2	3473.0	88091724
	1989	0.15786	-13382.6	14862.9	89031524
	1990	0.17387	-16961.0	10598.4	90051524
	1991	0.15481	-15320.9	12855.8	91032724
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.01321	-7880.1	6156.6	87123124
	1988	0.01353	-13244.2	7042.1	88123124
	1989	0.01605	-7431.5	6691.3	89123124
	1990	0.01453	-17320.5	10000.0	90123124
	1991	0.01577	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.66200	142.7	2343.7	87091812
	1988	1.39255	-3438.3	2498.1	88080211

	1989	1.29032	2112.6	-3973.3	89042711
	1990	2.11657	964.2	-1149.1	90072212
	1991	1.45332	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	0.87227	-15760.2	12313.2	87060503
	1988	0.87767	-15760.2	12313.2	88091003
	1989	0.83363	-19805.4	2783.5	89091103
	1990	0.83225	-20000.0	0.0	90031003
	1991	0.89280	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.42990	-15760.2	12313.2	87060508
	1988	0.49995	-19562.9	-4158.2	88091624
	1989	0.42702	14694.6	-20225.4	89021108
	1990	0.47556	-15760.2	12313.2	90123024
	1991	0.45162	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.20776	-11490.7	9641.8	87080724
	1988	0.20727	-19696.2	3473.0	88091724
	1989	0.18493	-13382.6	14862.9	89031524
	1990	0.20877	-16961.0	10598.4	90051524
	1991	0.18068	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.01341	-7880.1	6156.6	87123124
	1988	0.01376	-13244.2	7042.1	88123124
	1989	0.01629	-7431.5	6691.3	89123124
	1990	0.01482	-17320.5	10000.0	90123124
	1991	0.01599	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.66497	142.7	2343.7	87091812
	1988	1.39286	-3438.3	2498.1	88080211
	1989	1.30493	2230.0	-4194.0	89042711
	1990	2.12084	964.2	-1149.1	90072212
	1991	1.57360	1594.1	2076.7	91061812
HIGH 3-Hour					
	1987	0.88273	-15760.2	12313.2	87060503
	1988	0.88842	-15760.2	12313.2	88091003
	1989	0.84282	-19805.4	2783.5	89091103
	1990	0.84138	-20000.0	0.0	90031003
	1991	0.90376	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.43509	-15760.2	12313.2	87060508
	1988	0.50768	-19562.9	-4158.2	88091624
	1989	0.43386	14694.6	-20225.4	89021108
	1990	0.48149	-15760.2	12313.2	90123024
	1991	0.45686	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.20970	-11490.7	9641.8	87080724
	1988	0.20964	-19696.2	3473.0	88091724
	1989	0.18761	-13382.6	14862.9	89031524
	1990	0.21251	-16961.0	10598.4	90051524
	1991	0.18494	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.01391	-7880.1	6156.6	87123124
	1988	0.01438	-13244.2	7042.1	88123124
	1989	0.01676	-7431.5	6691.3	89123124
	1990	0.01557	-17320.5	10000.0	90123124
	1991	0.01657	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.67220	142.7	2343.7	87091812
	1988	1.39410	-3438.3	2498.1	88080211
	1989	1.44737	-1087.0	-4053.7	89041111
	1990	2.13163	964.2	-1149.1	90072212
	1991	1.58480	1594.1	2076.7	91061812
HIGH 3-Hour					
	1987	0.90858	-15760.2	12313.2	87060503
	1988	0.91504	-15760.2	12313.2	88091003
	1989	0.86551	-19805.4	2783.5	89091103
	1990	0.86383	-20000.0	0.0	90031003
	1991	0.90890	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.44791	-15760.2	12313.2	87060508
	1988	0.52647	-19562.9	-4158.2	88091624

	1989	0.45181	11755.7	-16180.3	89021108
	1990	0.49613	-15760.2	12313.2	90123024
	1991	0.46980	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.21476	-7660.4	6427.9	87080724
	1988	0.21552	-19696.2	3473.0	88091724
	1989	0.19514	-13382.6	14862.9	89031524
	1990	0.22153	-16961.0	10598.4	90051524
	1991	0.19542	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.01586	-8660.3	5000.0	87123124
	1988	0.01640	-13244.2	7042.1	88123124
	1989	0.01868	-7880.1	6156.6	89123124
	1990	0.01814	-12990.4	7500.0	90123124
	1991	0.01842	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.70208	142.7	2343.7	87091812
	1988	1.51505	-3785.6	2343.7	88083111
	1989	1.69107	-1863.1	3819.9	89062811
	1990	2.16910	964.2	-1149.1	90072212
	1991	1.70497	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	0.99324	-15760.2	12313.2	87060503
	1988	1.00283	-15760.2	12313.2	88091003
	1989	0.94477	-14854.0	2087.6	89091103
	1990	0.94661	-15000.0	0.0	90031003
	1991	0.98940	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.49027	-16961.0	10598.4	87062008
	1988	0.58505	-19562.9	-4158.2	88091624
	1989	0.51800	11755.7	-16180.3	89021108
	1990	0.54412	-15760.2	12313.2	90123024
	1991	0.52501	-4728.1	3694.0	91072416
HIGH 24-Hour					
	1987	0.23379	-7660.4	6427.9	87080724
	1988	0.23491	-19696.2	3473.0	88091724
	1989	0.21563	-13382.6	14862.9	89031524
	1990	0.24900	-16961.0	10598.4	90051524
	1991	0.22936	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5059				
Annual					
	1987	0.01605	-8660.3	5000.0	87123124
	1988	0.01659	-13244.2	7042.1	88123124
	1989	0.01885	-7880.1	6156.6	89123124
	1990	0.01837	-12990.4	7500.0	90123124
	1991	0.01865	-13244.2	7042.1	91123124
HIGH 1-Hour					
	1987	1.70520	142.7	2343.7	87091812
	1988	1.51566	-3785.6	2343.7	88083111
	1989	1.69112	-1863.1	3819.9	89062811
	1990	2.17220	964.2	-1149.1	90072212
	1991	1.71962	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	1.00024	-15760.2	12313.2	87060503
	1988	1.01004	-15760.2	12313.2	88091003
	1989	0.95185	-14854.0	2087.6	89091103
	1990	0.95372	-15000.0	0.0	90031003
	1991	0.99610	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.49616	-16961.0	10598.4	87062008
	1988	0.59038	-19562.9	-4158.2	88091624
	1989	0.52532	11755.7	-16180.3	89021108
	1990	0.54813	-15760.2	12313.2	90123024
	1991	0.52871	-4531.1	3540.1	91072416
HIGH 24-Hour					
	1987	0.23540	-7660.4	6427.9	87080724
	1988	0.23650	-19696.2	3473.0	88091724
	1989	0.21752	-13382.6	14862.9	89031524
	1990	0.25168	-16961.0	10598.4	90051524
	1991	0.23226	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.01633	-8660.3	5000.0	87123124

	1988	0.01684	-13244.2	7042.1	88123124
	1989	0.01907	-7880.1	6156.6	89123124
	1990	0.01864	-12990.4	7500.0	90123124
	1991	0.01893	-13244.2	7042.1	91123124
HIGH 1-Hour					
	1987	1.70904	142.7	2343.7	87091812
	1988	1.51645	-3785.6	2343.7	88083111
	1989	1.69124	-1863.1	3819.9	89062811
	1990	2.17607	964.2	-1149.1	90072212
	1991	1.73691	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	1.00884	-15760.2	12313.2	87060503
	1988	1.01893	-15760.2	12313.2	88091003
	1989	0.96055	-14854.0	2087.6	89091103
	1990	0.96238	-15000.0	0.0	90031003
	1991	1.00427	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.50290	-16961.0	10598.4	87062008
	1988	0.59665	-19562.9	-4158.2	88091624
	1989	0.53370	11755.7	-16180.3	89021108
	1990	0.55302	-15760.2	12313.2	90123024
	1991	0.53340	-4531.1	3540.1	91072416
HIGH 24-Hour					
	1987	0.23740	-7660.4	6427.9	87080724
	1988	0.23847	-19696.2	3473.0	88091724
	1989	0.21983	-13382.6	14862.9	89031524
	1990	0.25475	-16961.0	10598.4	90051524
	1991	0.23574	-13907.8	5619.1	91052124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

SIMPLE CYCLE
HIGHER POWER MODE
SUMMARY FILE

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :SIMPLE.O87
ISCST3 OUTPUT FILE NUMBER 2 :SIMPLE.O88
ISCST3 OUTPUT FILE NUMBER 3 :SIMPLE.O89
ISCST3 OUTPUT FILE NUMBER 4 :SIMPLE.O90
ISCST3 OUTPUT FILE NUMBER 5 :SIMPLE.O91
First title for last output file is: FPL MARTIN PROPOSED SIMPLE CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, N

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: HPM35					
Annual					
	1987	0.01044	-7880.1	6156.6	87123124
	1988	0.01062	-17658.9	9389.4	88123124
	1989	0.01260	-7193.4	6946.6	89123124
	1990	0.01114	-17320.5	10000.0	90123124
	1991	0.01231	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.13127	2309.0	1542.6	87081113
	1988	1.10051	-1309.3	-4566.0	88042811
	1989	1.09969	-4608.9	-1149.1	89051614
	1990	1.16097	2348.7	1512.9	90082313
	1991	1.15197	1785.4	2285.2	91071217
HIGH 3-Hour					
	1987	0.72190	1403.4	-6602.5	87102612
	1988	0.74034	1663.3	7825.2	88060815
	1989	0.69922	-19805.4	2783.5	89091103
	1990	0.69998	-20000.0	0.0	90031003
	1991	0.73770	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.35617	-3747.5	-4922.0	87053016
	1988	0.39839	-19562.9	-4158.2	88091624
	1989	0.39694	11183.9	-16580.8	89021108
	1990	0.42589	-5624.4	1195.5	90081616
	1991	0.37552	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.15805	14386.8	-13893.2	87120524
	1988	0.16020	-19696.2	3473.0	88091724
	1989	0.14804	-13382.6	14862.9	89031524
	1990	0.16886	-5624.4	1195.5	90081624
	1991	0.14702	-15320.9	12855.8	91032724
SOURCE GROUP ID: HPM59					
Annual					
	1987	0.01067	-7880.1	6156.6	87123124
	1988	0.01085	-17658.9	9389.4	88123124
	1989	0.01297	-7193.4	6946.6	89123124
	1990	0.01142	-17320.5	10000.0	90123124
	1991	0.01265	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.13672	2309.0	1542.6	87081113
	1988	1.14444	-4921.8	937.3	88080411
	1989	1.13349	-4750.0	0.0	89041311
	1990	1.16655	2348.7	1512.9	90082313
	1991	1.17895	1785.4	2285.2	91071217
HIGH 3-Hour					
	1987	0.73546	-15760.2	12313.2	87060503
	1988	0.74176	1663.3	7825.2	88060815
	1989	0.71166	-19805.4	2783.5	89091103
	1990	0.71237	-20000.0	0.0	90031003
	1991	0.75218	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.36261	-3747.5	-4922.0	87053016
	1988	0.40750	-19562.9	-4158.2	88091624
	1989	0.40508	11183.9	-16580.8	89021108
	1990	0.42678	-5624.4	1195.5	90081616
	1991	0.38251	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.15713	14386.8	-13893.2	87120524
	1988	0.16332	-19696.2	3473.0	88091724
	1989	0.15139	-13382.6	14862.9	89031524

	1990	0.16939	-5624.4	1195.5	90081624
	1991	0.14997	-15320.9	12855.8	91032724
SOURCE GROUP ID:	HPM95				
Annual					
	1987	0.01091	-7880.1	6156.6	87123124
	1988	0.01125	-17658.9	9389.4	88123124
	1989	0.01328	-7193.4	6946.6	89123124
	1990	0.01183	-17320.5	10000.0	90123124
	1991	0.01296	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.14262	2309.0	1542.6	87081113
	1988	1.16097	-4581.3	2343.7	88071112
	1989	1.13411	-4750.0	0.0	89041311
	1990	1.27524	-1846.3	2343.7	90082412
	1991	1.20910	1723.8	2206.4	91071217
HIGH 3-Hour					
	1987	0.75087	-15760.2	12313.2	87060503
	1988	0.75242	-15760.2	12313.2	88091003
	1989	0.72546	-19805.4	2783.5	89091103
	1990	0.72613	-20000.0	0.0	90031003
	1991	0.76833	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.36975	-15760.2	12313.2	87060508
	1988	0.41802	-19562.9	-4158.2	88091624
	1989	0.41416	11183.9	-16580.8	89021108
	1990	0.42785	-5624.4	1195.5	90081616
	1991	0.39028	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.16154	14386.8	-13893.2	87120524
	1988	0.16679	-19696.2	3473.0	88091724
	1989	0.15608	-13382.6	14862.9	89031524
	1990	0.17223	-16961.0	10598.4	90051524
	1991	0.15324	-15320.9	12855.8	91032724

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

SIMPLE CYCLE
FUEL OIL
SUMMARY FILE

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :SIMPLE.087
ISCST3 OUTPUT FILE NUMBER 2 :SIMPLE.088
ISCST3 OUTPUT FILE NUMBER 3 :SIMPLE.089
ISCST3 OUTPUT FILE NUMBER 4 :SIMPLE.090
ISCST3 OUTPUT FILE NUMBER 5 :SIMPLE.091
First title for last output file is: FPL MARTIN PROPOSED SIMPLE CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, F

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BASE35				
Annual					
	1987	0.01156	-7880.1	6156.6	87123124
	1988	0.01197	-13244.2	7042.1	88123124
	1989	0.01391	-7193.4	6946.6	89123124
	1990	0.01235	-17320.5	10000.0	90123124
	1991	0.01359	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.25527	2309.0	1542.6	87081113
	1988	1.22266	-1309.3	-4566.0	88042811
	1989	1.22173	-4608.9	-1149.1	89051614
	1990	1.28822	2348.7	1512.9	90082313
	1991	1.27033	1785.4	2285.2	91071217
HIGH 3-Hour					
	1987	0.80164	1403.4	-6602.5	87102612
	1988	0.82219	1663.3	7825.2	88060815
	1989	0.77279	-19805.4	2783.5	89091103
	1990	0.77345	-20000.0	0.0	90031003
	1991	0.81445	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.39335	-3747.5	-4922.0	87053016
	1988	0.44137	1767.3	8314.3	88060816
	1989	0.43805	11183.9	-16580.8	89021108
	1990	0.47283	-5624.4	1195.5	90081616
	1991	0.41494	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.17392	14386.8	-13893.2	87120524
	1988	0.17697	-19696.2	3473.0	88091724
	1989	0.16334	-13382.6	14862.9	89031524
	1990	0.18734	-5624.4	1195.5	90081624
	1991	0.16235	-15320.9	12855.8	91032724
SOURCE GROUP ID:	BASE59				
Annual					
	1987	0.01180	-7880.1	6156.6	87123124
	1988	0.01200	-17658.9	9389.4	88123124
	1989	0.01435	-7193.4	6946.6	89123124
	1990	0.01262	-17320.5	10000.0	90123124
	1991	0.01391	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.26179	2309.0	1542.6	87081113
	1988	1.27144	-4921.8	937.3	88080411
	1989	1.25933	-4750.0	0.0	89041311
	1990	1.29489	2348.7	1512.9	90082313
	1991	1.30211	1785.4	2285.2	91071217
HIGH 3-Hour					
	1987	0.81363	-15760.2	12313.2	87060503
	1988	0.82381	1663.3	7825.2	88060815
	1989	0.78762	-19805.4	2783.5	89091103
	1990	0.78823	-20000.0	0.0	90031003
	1991	0.83171	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.40107	-3747.5	-4922.0	87053016
	1988	0.45006	-19562.9	-4158.2	88091624
	1989	0.44775	11183.9	-16580.8	89021108
	1990	0.47398	-5624.4	1195.5	90081616
	1991	0.42327	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.17320	14386.8	-13893.2	87120524
	1988	0.18069	-19696.2	3473.0	88091724
	1989	0.16732	-13382.6	14862.9	89031524

	1990	0.18829	-5624.4	1195.5	90081624
	1991	0.16586	-15320.9	12855.8	91032724
SOURCE GROUP ID:	BASE95				
Annual					
	1987	0.01239	-7880.1	6156.6	87123124
	1988	0.01283	-13244.2	7042.1	88123124
	1989	0.01522	-7193.4	6946.6	89123124
	1990	0.01354	-17320.5	10000.0	90123124
	1991	0.01491	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.27650	3194.9	-57.4	87071513
	1988	1.34499	-5110.1	1288.9	88072412
	1989	1.26105	-4750.0	0.0	89041311
	1990	1.42366	-1846.3	2343.7	90082412
	1991	1.37488	1723.8	2206.4	91071217
HIGH 3-Hour					
	1987	0.85083	-15760.2	12313.2	87060503
	1988	0.85312	-15760.2	12313.2	88091003
	1989	0.82095	-19805.4	2783.5	89091103
	1990	0.82129	-20000.0	0.0	90031003
	1991	0.87038	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.41902	-15760.2	12313.2	87060508
	1988	0.47486	-19562.9	-4158.2	88091624
	1989	0.44247	11755.7	-16180.3	89021108
	1990	0.47680	-5379.8	1143.5	90081616
	1991	0.44205	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.18337	14386.8	-13893.2	87120524
	1988	0.18909	-19696.2	3473.0	88091724
	1989	0.17739	-13382.6	14862.9	89031524
	1990	0.19578	-16961.0	10598.4	90051524
	1991	0.17376	-15320.9	12855.8	91032724
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.01446	-7880.1	6156.6	87123124
	1988	0.01469	-13244.2	7042.1	88123124
	1989	0.01756	-7431.5	6691.3	89123124
	1990	0.01584	-17320.5	10000.0	90123124
	1991	0.01726	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.43842	3194.9	-57.4	87071513
	1988	1.46769	-3344.1	3011.1	88080911
	1989	1.43282	2112.6	-3973.3	89042711
	1990	2.34681	964.2	-1149.1	90072212
	1991	1.58904	1662.3	2127.6	91071217
HIGH 3-Hour					
	1987	0.95715	-15760.2	12313.2	87060503
	1988	0.96276	-15760.2	12313.2	88091003
	1989	0.91562	-19805.4	2783.5	89091103
	1990	0.91427	-20000.0	0.0	90031003
	1991	0.97959	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.47170	-15760.2	12313.2	87060508
	1988	0.54714	-19562.9	-4158.2	88091624
	1989	0.49980	11183.9	-16580.8	89021108
	1990	0.52160	-15760.2	12313.2	90123024
	1991	0.49574	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.22861	-11490.7	9641.8	87080724
	1988	0.22756	-19696.2	3473.0	88091724
	1989	0.20242	-13382.6	14862.9	89031524
	1990	0.22807	-16961.0	10598.4	90051524
	1991	0.19598	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.01461	-7880.1	6156.6	87123124
	1988	0.01497	-13244.2	7042.1	88123124
	1989	0.01774	-7431.5	6691.3	89123124
	1990	0.01604	-17320.5	10000.0	90123124
	1991	0.01743	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.84548	142.7	2343.7	87091812
	1988	1.54719	-3438.3	2498.1	88080211

	1989	1.43339	2112.6	-3973.3	89042711
	1990	2.35005	964.2	-1149.1	90072212
	1991	1.60747	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	0.96527	-15760.2	12313.2	87060503
	1988	0.97107	-15760.2	12313.2	88091003
	1989	0.92275	-19805.4	2783.5	89091103
	1990	0.92139	-20000.0	0.0	90031003
	1991	0.98815	6840.4	-18793.8	91011803
HIGH 8-Hour					
	1987	0.47572	-15760.2	12313.2	87060508
	1988	0.55329	-19562.9	-4158.2	88091624
	1989	0.47252	14694.6	-20225.4	89021108
	1990	0.52620	-15760.2	12313.2	90123024
	1991	0.49980	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.23010	-11490.7	9641.8	87080724
	1988	0.22939	-19696.2	3473.0	88091724
	1989	0.20450	-13382.6	14862.9	89031524
	1990	0.23110	-16961.0	10598.4	90051524
	1991	0.19931	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.01506	-7880.1	6156.6	87123124
	1988	0.01559	-13244.2	7042.1	88123124
	1989	0.01824	-7431.5	6691.3	89123124
	1990	0.01684	-17320.5	10000.0	90123124
	1991	0.01800	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.85349	142.7	2343.7	87091812
	1988	1.54813	-3438.3	2498.1	88080211
	1989	1.45092	2230.0	-4194.0	89042711
	1990	2.36165	964.2	-1149.1	90072212
	1991	1.75391	1594.1	2076.7	91061812
HIGH 3-Hour					
	1987	0.99345	-15760.2	12313.2	87060503
	1988	1.00008	-15760.2	12313.2	88091003
	1989	0.94753	-19805.4	2783.5	89091103
	1990	0.94591	-20000.0	0.0	90031003
	1991	0.99451	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.48970	-15760.2	12313.2	87060508
	1988	0.57372	-19562.9	-4158.2	88091624
	1989	0.49069	14694.6	-20225.4	89021108
	1990	0.54215	-15760.2	12313.2	90123024
	1991	0.51392	-14862.9	13382.6	91071808
HIGH 24-Hour					
	1987	0.23535	-11490.7	9641.8	87080724
	1988	0.23580	-19696.2	3473.0	88091724
	1989	0.21270	-13382.6	14862.9	89031524
	1990	0.24088	-16961.0	10598.4	90051524
	1991	0.21071	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.01725	-12990.4	7500.0	87123124
	1988	0.01794	-13244.2	7042.1	88123124
	1989	0.02045	-7660.4	6427.9	89123124
	1990	0.01981	-12990.4	7500.0	90123124
	1991	0.02027	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.88566	142.7	2343.7	87091812
	1988	1.68239	-3785.6	2343.7	88083111
	1989	1.68677	3200.0	-456.2	89052111
	1990	2.40465	964.2	-1149.1	90072212
	1991	1.87073	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	1.09156	-15760.2	12313.2	87060503
	1988	1.10175	-15760.2	12313.2	88091003
	1989	1.03754	-14854.0	2087.6	89091103
	1990	1.03975	-15000.0	0.0	90031003
	1991	1.08792	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.53838	-15760.2	12313.2	87060508
	1988	0.64172	-19562.9	-4158.2	88091624

	1989	0.56606	11755.7	-16180.3	89021108
	1990	0.59774	-15760.2	12313.2	90123024
	1991	0.57701	-4728.1	3694.0	91072416
HIGH 24-Hour					
	1987	0.25698	-7660.4	6427.9	87080724
	1988	0.25825	-19696.2	3473.0	88091724
	1989	0.23639	-13382.6	14862.9	89031524
	1990	0.27274	-16961.0	10598.4	90051524
	1991	0.25005	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5059				
Annual					
	1987	0.01754	-12990.4	7500.0	87123124
	1988	0.01815	-13244.2	7042.1	88123124
	1989	0.02065	-7880.1	6156.6	89123124
	1990	0.02006	-12990.4	7500.0	90123124
	1991	0.02038	-7880.1	6156.6	91123124
HIGH 1-Hour					
	1987	1.88931	142.7	2343.7	87091812
	1988	1.68304	-3785.6	2343.7	88083111
	1989	1.87895	-1863.1	3819.9	89062811
	1990	2.40822	964.2	-1149.1	90072212
	1991	1.88759	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	1.09963	-15760.2	12313.2	87060503
	1988	1.11007	-15760.2	12313.2	88091003
	1989	1.04568	-14854.0	2087.6	89091103
	1990	1.04790	-15000.0	0.0	90031003
	1991	1.09562	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.54276	-16961.0	10598.4	87062008
	1988	0.64778	-19562.9	-4158.2	88091624
	1989	0.57345	11755.7	-16180.3	89021108
	1990	0.60234	-15760.2	12313.2	90123024
	1991	0.58117	-4728.1	3694.0	91072416
HIGH 24-Hour					
	1987	0.25883	-7660.4	6427.9	87080724
	1988	0.26009	-19696.2	3473.0	88091724
	1989	0.23855	-13382.6	14862.9	89031524
	1990	0.27576	-16961.0	10598.4	90051524
	1991	0.25337	-13907.8	5619.1	91052124
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.01822	-8660.3	5000.0	87123124
	1988	0.01879	-13244.2	7042.1	88123124
	1989	0.02129	-7880.1	6156.6	89123124
	1990	0.02080	-12990.4	7500.0	90123124
	1991	0.02116	-13244.2	7042.1	91123124
HIGH 1-Hour					
	1987	1.90014	142.7	2343.7	87091812
	1988	1.68521	-3785.6	2343.7	88083111
	1989	1.87921	-1863.1	3819.9	89062811
	1990	2.41909	964.2	-1149.1	90072212
	1991	1.93556	1633.8	2047.0	91071217
HIGH 3-Hour					
	1987	1.12369	-15760.2	12313.2	87060503
	1988	1.13498	-15760.2	12313.2	88091003
	1989	1.07006	-14854.0	2087.6	89091103
	1990	1.07211	-15000.0	0.0	90031003
	1991	1.11849	-14862.9	13382.6	91032124
HIGH 8-Hour					
	1987	0.56107	-16961.0	10598.4	87062008
	1988	0.66502	-19562.9	-4158.2	88091624
	1989	0.59592	11755.7	-16180.3	89021108
	1990	0.61604	-15760.2	12313.2	90123024
	1991	0.59415	-4531.1	3540.1	91072416
HIGH 24-Hour					
	1987	0.26442	-7660.4	6427.9	87080724
	1988	0.26560	-19696.2	3473.0	88091724
	1989	0.24500	-13382.6	14862.9	89031524
	1990	0.28410	-16961.0	10598.4	90051524
	1991	0.26306	-13907.8	5619.1	91052124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

COMBINED CYCLE LOAD ANALYSIS
ISCST3 SUMMARY

Table F-2. Maximum Pollutant Concentrations Predicted for One Combustion Turbine in Combined Cycle Operation

	Maximum Emission Rates (lb/hr) by Operating Load and Air Inlet Temperature											Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Inlet Temperature [a]						
	Power Augmentation	Baseload			75% Load			50% Load			Averaging	Power Augmentation	Baseload			75% Load		
Pollutant	80°F	95°F	59°F	35°F	95°F	59°F	35°F	95°F	59°F	35°F	Time	80°F	95°F	59°F	35°F	95°F	59°F	35°F
Natural Gas [b]																		
Generic (9 g/s)	71 43	71 43	71 43	71.43	71 43	71 43	71 43	71.43	71 43	71 43	Annual	0 158	0 196	0 178	0 167	0 257	0 239	0 236
											1-Hour	7 805	8 064	8 068	7.799	10 155	10 144	10 146
											3-Hour	4 896	5 609	5 364	5 185	6 797	6 443	6 383
											8-Hour	3 257	3.943	3 633	3 427	4.978	4 667	4 623
											24-Hour	2 277	2 638	2 476	2 364	3.155	2 988	2.965
SO_2	12.5	11.9	12 8	13.3	7.3	7.9	8 3	5 9	6 4	6 6	Annual	0 0277	0 0326	0 0319	0 0310	0 0262	0 0266	0 0273
											24-Hour	0 400	0 439	0 445	0 440	0 322	0 333	0 342
											3-Hour	0 86	0 93	0 96	0 96	0 69	0 72	0 74
PM_{10}	17 0	16 9	17.1	17.2	10 5	10 6	10 7	10 2	10 3	10 3	Annual	0 0377	0 0463	0 0425	0 0401	0 0377	0 0355	0 0353
											24-Hour	0 54	0 62	0.59	0 57	0 46	0 44	0 44
NO_x/NO_2	30 9	31 2	33 1	33 9	16 8	18 3	19 0	13.4	14 6	15.1	Annual	0 068	0 086	0 082	0 079	0 060	0 061	0 063
CO	89 0	69 5	71.5	72 6	21.7	23 5	24 4	18 3	19 5	20 1	8-Hour	4 06	3 84	3 64	3 49	1.50	1 54	1.58
											1-Hour	9.72	7.85	8 08	7.93	3 08	3 34	3 46
Fuel Oil																		
Generic (9 g/s)		71 43	71.43	71 43	71 43	71 43	71.43	71 43	71.43	71 43	Annual	NA	0 079	0 070	0 065	0 120	0 114	0 110
											1-Hour	NA	5.309	5 246	5 214	6 013	6 011	6 011
											3-Hour	NA	2 889	2 644	2 522	3 912	3 782	3.710
											8-Hour	NA	2 068	1.856	1.734	2 687	2 615	2 575
											24-Hour	NA	1.336	1.198	1.119	1 834	1.751	1.705
SO_2		89.1	98 6	103 1	72 2	78 8	82 0	57.7	62 6	64 7	Annual	NA	0 0991	0 0968	0 0943	0 1212	0 1255	0 1268
											24-Hour	NA	1 667	1.654	1 616	1.852	1.931	1 957
											3-Hour	NA	3.60	3 65	3 64	3 95	4 17	4.26
PM_{10}		35 0	36 9	37.8	31.6	32 9	33 6	28 7	29 7	30 1	Annual	NA	0 0390	0 0362	0 0346	0 0530	0 0524	0 0519
											24-Hour	NA	0 65	0 62	0 59	0 81	0 81	0 80
NO_x/NO_2		82 3	91 2	95 4	66 1	72 2	75 0	52 3	56 8	58 7	Annual	NA	0 092	0 090	0 087	0 111	0 115	0 116
CO		58 9	64 7	68 1	48 3	51.7	53 5	41.0	43 2	44 3	8-Hour	NA	1 70	1 68	1 65	1.82	1 89	1.93
											1-Hour	NA	4 4	4.7	5 0	4 1	4 4	4 5

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 1987 to 1991 of surface and upper air data from the National Weather Service station at Palm Beach International Airport

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79 37 lb/hr (10 g/s) Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s

[b] Duct firing included for baseload operating load Duct firing based on natural gas-fired duct burner with maximum heat input rate of 550 mmBtu/hr (HHV)

COMBINED CYCLE
NATURAL GAS
SUMMARY FILE

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :COMBINED.087
ISCST3 OUTPUT FILE NUMBER 2 :COMBINED.088
ISCST3 OUTPUT FILE NUMBER 3 :COMBINED.089
ISCST3 OUTPUT FILE NUMBER 4 :COMBINED.090
ISCST3 OUTPUT FILE NUMBER 5 :COMBINED.091
First title for last output file is: FPL MARTIN PROPOSED COMBINED CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, N

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: BSDB35					
Annual					
	1987	0.13567	-4034.3	2343.7	87123124
	1988	0.12910	-4497.9	146.1	88123124
	1989	0.14392	-2194.4	2343.7	89123124
	1990	0.16678	-4084.0	2343.7	90123124
	1991	0.15599	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.28355	-4035.8	-1876.0	87092608
	1988	7.54417	-2940.3	2343.7	88100208
	1989	7.22362	744.6	-877.3	89092113
	1990	7.79895	-4680.7	2343.7	90071713
	1991	7.19051	2587.0	1334.9	91030916
HIGH 3-Hour					
	1987	4.84497	2110.4	1690.9	87062712
	1988	4.81775	1765.9	-938.9	88042712
	1989	4.16450	-2343.6	2343.7	89060515
	1990	4.48792	-3993.3	-2120.9	90100812
	1991	5.18460	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.42671	2070.7	1720.6	87062716
	1988	3.21197	-4265.2	-553.4	88013008
	1989	2.77621	-4163.2	-1141.2	89072516
	1990	3.25439	-4146.2	-1239.2	90030816
	1991	3.15764	-5416.2	1860.3	91052124
HIGH 24-Hour					
	1987	2.36438	-4403.8	-29.7	87111624
	1988	2.08784	-4248.2	-651.4	88013024
	1989	1.44017	-3638.7	3053.2	89040424
	1990	2.22336	-1746.9	2343.7	90101024
	1991	2.06754	-5277.4	2343.7	91052124
SOURCE GROUP ID: BSDB59					
Annual					
	1987	0.14457	-4034.3	2343.7	87123124
	1988	0.13656	-4474.4	102.2	88123124
	1989	0.15307	-3686.2	2343.7	89123124
	1990	0.17777	-4034.3	2343.7	90123124
	1991	0.16576	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.46932	2901.6	-1957.2	87102808
	1988	7.55581	-2940.3	2343.7	88100208
	1989	7.48286	744.6	-877.3	89092113
	1990	8.06768	-1408.4	2648.8	90050507
	1991	7.43920	2220.9	-863.9	91021514
HIGH 3-Hour					
	1987	5.03244	2110.4	1690.9	87062712
	1988	5.04629	1765.9	-938.9	88042712
	1989	4.31987	-2343.6	2343.7	89060515
	1990	4.72015	-3993.3	-2120.9	90100812
	1991	5.36446	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.63269	2070.7	1720.6	87062716
	1988	3.38747	-4265.2	-553.4	88013008
	1989	2.90578	-4163.2	-1141.2	89072516
	1990	3.39754	-4146.2	-1239.2	90030816
	1991	3.24365	-5416.2	1860.3	91052124
HIGH 24-Hour					
	1987	2.47604	-4403.8	-29.7	87111624
	1988	2.19633	-4248.2	-651.4	88013024
	1989	1.54798	-3447.2	2892.5	89040424

	1990	2.34708	-1746.9	2343.7	90101024
	1991	2.12633	-5277.4	2343.7	91052124
SOURCE GROUP ID:	BSDB95				
Annual					
	1987	0.15955	-3984.6	2343.7	87123124
	1988	0.14966	-4450.9	58.2	88123124
	1989	0.16890	-2194.4	2343.7	89123124
	1990	0.19569	-4034.3	2343.7	90123124
	1991	0.18075	-4133.7	2343.7	91123124
HIGH 1-Hour					
	1987	7.70190	2110.4	1690.9	87012212
	1988	7.57573	-2940.3	2343.7	88100208
	1989	7.96845	744.6	-877.3	89092113
	1990	8.06396	-1408.4	2648.8	90050507
	1991	7.97361	2220.9	-863.9	91021514
HIGH 3-Hour					
	1987	5.30467	2110.4	1690.9	87062712
	1988	5.41623	2070.7	1720.6	88110512
	1989	4.54706	-2343.6	2343.7	89060515
	1990	5.05213	-3993.3	-2120.9	90100812
	1991	5.60884	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.94310	2070.7	1720.6	87062716
	1988	3.64808	-4265.2	-553.4	88013008
	1989	3.10010	-4163.2	-1141.2	89072516
	1990	3.61994	-4137.8	-1288.2	90111424
	1991	3.40110	-4112.3	-1435.2	91122008
HIGH 24-Hour					
	1987	2.63780	-4403.8	-29.7	87111624
	1988	2.35662	-4248.2	-651.4	88013024
	1989	1.72367	-3255.7	2731.9	89040424
	1990	2.53735	-1746.9	2343.7	90101024
	1991	2.22535	-4265.2	-553.4	91102424
SOURCE GROUP ID:	POWAUG				
Annual					
	1987	0.12847	-4034.3	2343.7	87123124
	1988	0.12159	-4497.9	146.1	88123124
	1989	0.13597	-3984.6	2343.7	89123124
	1990	0.15794	-4084.0	2343.7	90123124
	1991	0.14759	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.13789	1389.3	-1438.7	87073110
	1988	7.53174	-2940.3	2343.7	88100208
	1989	6.85262	-2492.8	2343.7	89110808
	1990	7.80494	-4680.7	2343.7	90071713
	1991	6.94937	2587.0	1334.9	91030916
HIGH 3-Hour					
	1987	4.68179	2110.4	1690.9	87062712
	1988	4.50880	490.8	2343.7	88060815
	1989	4.02276	-2343.6	2343.7	89060515
	1990	4.26754	-3993.3	-2120.9	90100812
	1991	4.89611	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.25740	2070.7	1720.6	87062716
	1988	3.11487	-4265.2	-553.4	88013008
	1989	2.64945	-4163.2	-1141.2	89072516
	1990	3.15206	-4146.2	-1239.2	90030816
	1991	3.08093	-5416.2	1860.3	91052124
HIGH 24-Hour					
	1987	2.27730	-4403.8	-29.7	87111624
	1988	2.02443	-4248.2	-651.4	88013024
	1989	1.36645	-3638.7	3053.2	89040424
	1990	2.11421	-1746.9	2343.7	90101024
	1991	2.01510	-5277.4	2343.7	91052124
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.19435	-3885.1	2343.7	87123124
	1988	0.17897	-4427.3	14.3	88123124
	1989	0.20711	-2244.1	2343.7	89123124
	1990	0.23603	-3934.8	2343.7	90123124
	1991	0.21732	-4034.3	2343.7	91123124
HIGH 1-Hour					
	1987	10.10817	-4568.6	278.0	87092716
	1988	8.82316	-3387.8	2343.7	88081609

	1989	10.14642	1314.5	2472.3	89080808
	1990	9.92997	2338.3	-1350.0	90072807
	1991	9.51054	-2343.6	2343.7	91071707
HIGH 3-Hour					
	1987	5.87058	2110.4	1690.9	87062712
	1988	6.38304	2070.7	1720.6	88110512
	1989	5.14556	-4545.0	234.0	89012515
	1990	5.73981	-3993.3	-2120.9	90100812
	1991	6.17214	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	4.62271	2070.7	1720.6	87062716
	1988	4.15796	-4265.2	-553.4	88013008
	1989	3.53755	-4163.2	-1141.2	89072516
	1990	4.22298	-4137.8	-1288.2	90111424
	1991	3.97887	-4265.2	-553.4	91102408
HIGH 24-Hour					
	1987	2.96488	-4380.2	-73.7	87111624
	1988	2.67051	-4248.2	-651.4	88013024
	1989	2.18397	-2691.7	2343.7	89040424
	1990	2.95858	-1746.9	2343.7	90101024
	1991	2.61716	-4273.7	-504.4	91102424
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.19719	-3885.1	2343.7	87123124
	1988	0.18139	-4427.3	14.3	88123124
	1989	0.21090	-2244.1	2343.7	89123124
	1990	0.23916	-3934.8	2343.7	90123124
	1991	0.22024	-4034.3	2343.7	91123124
HIGH 1-Hour					
	1987	10.11642	-4568.6	278.0	87092716
	1988	8.82371	-3387.8	2343.7	88081609
	1989	10.14406	1314.5	2472.3	89080808
	1990	9.93477	2338.3	-1350.0	90072807
	1991	9.51203	-2343.6	2343.7	91071707
HIGH 3-Hour					
	1987	5.90555	2110.4	1690.9	87062712
	1988	6.44326	2070.7	1720.6	88110512
	1989	5.19794	-4545.0	234.0	89012515
	1990	5.77943	-3993.3	-2120.9	90100812
	1991	6.19704	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	4.66696	2070.7	1720.6	87062716
	1988	4.19699	-4265.2	-553.4	88013008
	1989	3.56443	-4163.2	-1141.2	89072516
	1990	4.26624	-4137.8	-1288.2	90111424
	1991	4.02422	-4265.2	-553.4	91102408
HIGH 24-Hour					
	1987	2.98643	-4380.2	-73.7	87111624
	1988	2.69401	-4248.2	-651.4	88013024
	1989	2.22178	-2691.7	2343.7	89040424
	1990	2.98819	-1746.9	2343.7	90101024
	1991	2.64373	-4273.7	-504.4	91102424
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.21278	-3835.4	2343.7	87123124
	1988	0.19444	-4427.3	14.3	88123124
	1989	0.22579	-2293.9	2343.7	89123124
	1990	0.25697	-3885.1	2343.7	90123124
	1991	0.23594	-4034.3	2343.7	91123124
HIGH 1-Hour					
	1987	10.15497	-4568.6	278.0	87092716
	1988	9.25711	957.7	-2631.1	88111108
	1989	10.13137	1314.5	2472.3	89080808
	1990	9.97589	2338.3	-1350.0	90072807
	1991	9.69013	1974.9	-866.2	91021517
HIGH 3-Hour					
	1987	6.11127	2110.4	1690.9	87062712
	1988	6.79712	2070.7	1720.6	88110512
	1989	5.48310	-4545.0	234.0	89012515
	1990	6.02199	-3993.3	-2120.9	90100812
	1991	6.39737	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	4.92781	2070.7	1720.6	87062716
	1988	4.39250	-4265.2	-553.4	88013008

	1989	3.73087	-4163.2	-1141.2	89072516
	1990	4.49746	-4137.8	-1288.2	90111424
	1991	4.27560	-4265.2	-553.4	91102408
HIGH 24-Hour					
	1987	3.10599	-4380.2	-73.7	87111624
	1988	2.81324	-4248.2	-651.4	88013024
	1989	2.42573	-2691.7	2343.7	89040424
	1990	3.15547	-1746.9	2343.7	90101024
	1991	2.79263	-4273.7	-504.4	91102424
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.27813	-3735.9	2343.7	87123124
	1988	0.25102	-4403.8	-29.7	88123124
	1989	0.30263	-2393.3	2343.7	89123124
	1990	0.32872	-3735.9	2343.7	90123124
	1991	0.30153	-3934.8	2343.7	91123124
HIGH 1-Hour					
	1987	13.35206	-3686.2	2343.7	87092717
	1988	11.32395	1335.1	-872.0	88042712
	1989	17.40424	935.1	-903.1	89073010
	1990	11.78090	1335.1	-872.0	90073013
	1991	11.60522	1236.7	-872.9	91081712
HIGH 3-Hour					
	1987	7.37890	1991.3	1780.0	87062715
	1988	8.38270	1581.2	-869.7	88042712
	1989	6.99538	-4851.1	805.4	89091103
	1990	7.65066	2467.9	1423.9	90030318
	1991	7.44454	746.7	-1024.1	91081612
HIGH 8-Hour					
	1987	6.01688	2070.7	1720.6	87062716
	1988	5.15913	-4001.8	-2071.9	88011616
	1989	4.44163	-4163.2	-1141.2	89072516
	1990	5.37395	-4137.8	-1288.2	90111424
	1991	5.35971	-1299.3	2343.7	91021916
HIGH 24-Hour					
	1987	3.55804	-4380.2	-73.7	87111624
	1988	3.23867	-4248.2	-651.4	88013024
	1989	3.25799	-2691.7	2343.7	89040424
	1990	3.85264	-1746.9	2343.7	90101024
	1991	3.37845	-4273.7	-504.4	91102424
SOURCE GROUP ID:	LD5059				
Annual					
	1987	0.27986	-3735.9	2343.7	87123124
	1988	0.25237	-4403.8	-29.7	88123124
	1989	0.30438	-2393.3	2343.7	89123124
	1990	0.33055	-3735.9	2343.7	90123124
	1991	0.30325	-3934.8	2343.7	91123124
HIGH 1-Hour					
	1987	13.35960	-3686.2	2343.7	87092717
	1988	11.34772	1335.1	-872.0	88042712
	1989	17.40389	935.1	-903.1	89073010
	1990	11.79558	1335.1	-872.0	90073013
	1991	11.62819	1236.7	-872.9	91081712
HIGH 3-Hour					
	1987	7.39936	1991.3	1780.0	87062715
	1988	8.40178	1581.2	-869.7	88042712
	1989	7.05633	-4851.1	805.4	89091103
	1990	7.69621	2467.9	1423.9	90030318
	1991	7.43802	746.7	-1024.1	91081612
HIGH 8-Hour					
	1987	6.03179	2070.7	1720.6	87062716
	1988	5.18316	-4001.8	-2071.9	88011616
	1989	4.45058	-4163.2	-1141.2	89072516
	1990	5.39148	-4137.8	-1288.2	90111424
	1991	5.39056	-1299.3	2343.7	91021916
HIGH 24-Hour					
	1987	3.56536	-4380.2	-73.7	87111624
	1988	3.24849	-4248.2	-651.4	88013024
	1989	3.27682	-2691.7	2343.7	89040424
	1990	3.86664	-1746.9	2343.7	90101024
	1991	3.38831	-4273.7	-504.4	91102424
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.29167	-3686.2	2343.7	87123124

	1988	0.26281	-4403.8	-29.7	88123124
	1989	0.31886	-2443.0	2343.7	89123124
	1990	0.34382	-3735.9	2343.7	90123124
	1991	0.31537	-3885.1	2343.7	91123124
HIGH 1-Hour					
	1987	13.37686	-3686.2	2343.7	87092717
	1988	13.61898	-752.3	2343.7	88081413
	1989	17.43065	935.1	-903.1	89073010
	1990	13.13930	1165.8	-1865.7	90051107
	1991	12.05632	1236.7	-872.9	91081712
HIGH 3-Hour					
	1987	7.70064	2348.7	1512.9	87041821
	1988	8.66945	1581.2	-869.7	88042712
	1989	7.36160	-4851.1	805.4	89091103
	1990	8.04685	2467.9	1423.9	90030318
	1991	7.72642	746.7	-1024.1	91081612
HIGH 8-Hour					
	1987	6.21355	2070.7	1720.6	87062716
	1988	5.34666	-4001.8	-2071.9	88011616
	1989	4.56896	-4163.2	-1141.2	89072516
	1990	5.55823	-1846.3	2343.7	90021608
	1991	5.60866	-1299.3	2343.7	91021916
HIGH 24-Hour					
	1987	3.63665	-4380.2	-73.7	87111624
	1988	3.31666	-4248.2	-651.4	88013024
	1989	3.42532	-2641.9	2343.7	89040424
	1990	3.98780	-1746.9	2343.7	90101024
	1991	3.48411	-4273.7	-504.4	91102424

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

COMBINED CYCLE
FUEL OIL
SUMMARY FILE

D:\martin\iscst3b\combined\oil\COMBOIL.SUM 1/23/02 8:50AM

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :comboil.087
ISCST3 OUTPUT FILE NUMBER 2 :comboil.088
ISCST3 OUTPUT FILE NUMBER 3 :comboil.089
ISCST3 OUTPUT FILE NUMBER 4 :comboil.090
ISCST3 OUTPUT FILE NUMBER 5 :comboil.091
First title for last output file is: FPL MARTIN PROPOSED COMBINED CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, F

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BSDB35				
Annual					
	1987	0.05345	-7794.2	4500.0	87123124
	1988	0.05165	-7495.4	261.8	88123124
	1989	0.06021	-3847.5	4273.1	89123124
	1990	0.06531	-7361.2	4250.0	90123124
	1991	0.06245	-7063.6	3755.8	91123124
HIGH 1-Hour					
	1987	4.37267	2547.3	1364.5	87072409
	1988	3.85409	-4205.7	-896.3	88073108
	1989	4.05146	2509.2	2786.8	89080909
	1990	5.21396	746.7	-1024.1	90081212
	1991	3.86139	-1539.1	4228.6	91073108
HIGH 3-Hour					
	1987	2.42739	2110.4	1690.9	87062712
	1988	2.40806	623.7	2934.4	88060815
	1989	2.45592	-2691.7	2343.7	89071515
	1990	2.28858	-2691.7	2343.7	90052815
	1991	2.52244	-2840.9	2343.7	91070615
HIGH 8-Hour					
	1987	1.44973	-4546.6	-2625.0	87110116
	1988	1.39883	-4273.7	-504.4	88061816
	1989	1.54198	-2343.6	2343.7	89060516
	1990	1.38194	-5286.9	-1516.0	90030816
	1991	1.73352	-5439.8	1904.2	91052124
HIGH 24-Hour					
	1987	0.95648	-6000.0	0.0	87111624
	1988	0.84407	-5941.6	-835.0	88013024
	1989	0.59259	-6691.3	7431.5	89031524
	1990	0.90512	-2645.0	3640.6	90101024
	1991	1.11907	-5526.1	2343.7	91052124
SOURCE GROUP ID:	BSDB59				
Annual					
	1987	0.05758	-7361.2	4250.0	87123124
	1988	0.05448	-6995.7	244.3	88123124
	1989	0.06403	-3680.2	4087.3	89123124
	1990	0.07011	-6928.2	4000.0	90123124
	1991	0.06674	-6622.1	3521.0	91123124
HIGH 1-Hour					
	1987	4.58986	-4615.7	365.9	87091110
	1988	3.81798	-4028.2	2517.1	88080108
	1989	4.82894	2825.3	1156.8	89073012
	1990	5.24568	746.7	-1024.1	90081212
	1991	3.87253	-4010.3	-2023.0	91102109
HIGH 3-Hour					
	1987	2.59036	2110.4	1690.9	87062712
	1988	2.53362	602.9	2836.6	88060815
	1989	2.57628	-2691.7	2343.7	89071515
	1990	2.42262	-2691.7	2343.7	90052815
	1991	2.64398	-2840.9	2343.7	91070615
HIGH 8-Hour					
	1987	1.58029	-3976.4	-2218.9	87110116
	1988	1.45231	-4282.1	-455.5	88061816
	1989	1.61462	-2343.6	2343.7	89060516
	1990	1.50128	-5046.6	-1447.1	90030816
	1991	1.85606	-5439.8	1904.2	91052124
HIGH 24-Hour					
	1987	1.03895	-5500.0	0.0	87111624
	1988	0.91792	-5694.0	-800.3	88013024
	1989	0.62955	-6946.6	7193.4	89031524

	1990	0.96497	-2498.1	3438.3	90101024
	1991	1.19833	-5476.3	2343.7	91052124
SOURCE GROUP ID:	BSDB95				
Annual					
	1987	0.06545	-6495.2	3750.0	87123124
	1988	0.06203	-6496.0	226.9	88123124
	1989	0.07269	-3345.6	3715.7	89123124
	1990	0.07948	-6495.2	3750.0	90123124
	1991	0.07600	-5959.9	3168.9	91123124
HIGH 1-Hour					
	1987	4.59656	-4615.7	365.9	87091110
	1988	4.83026	4851.5	1209.6	88112314
	1989	5.00736	899.1	-2225.2	89052509
	1990	5.30922	746.7	-1024.1	90081212
	1991	4.36367	2155.1	1940.5	91092610
HIGH 3-Hour					
	1987	2.88921	2110.4	1690.9	87062712
	1988	2.76357	582.2	2738.8	88060815
	1989	2.78195	-2691.7	2343.7	89071515
	1990	2.68565	-4497.9	146.1	90070712
	1991	2.84913	-2840.9	2343.7	91070615
HIGH 8-Hour					
	1987	1.81760	-3976.4	-2218.9	87110116
	1988	1.63722	-5446.5	-765.5	88013008
	1989	1.75377	-2343.6	2343.7	89060516
	1990	1.73453	-4566.0	-1309.3	90030816
	1991	2.06766	-5439.8	1904.2	91052124
HIGH 24-Hour					
	1987	1.19888	-5000.0	0.0	87111624
	1988	1.06253	-5198.9	-730.7	88013024
	1989	0.69574	-6946.6	7193.4	89031524
	1990	1.09381	-2351.1	3236.1	90101024
	1991	1.33626	-5426.6	2343.7	91052124
SOURCE GROUP ID:	LD7535				
Annual					
	1987	0.09041	-5196.1	3000.0	87123124
	1988	0.08560	-5246.8	183.2	88123124
	1989	0.09825	-2676.5	2972.6	89123124
	1990	0.11049	-4979.6	2875.0	90123124
	1991	0.10454	-4332.6	2343.7	91123124
HIGH 1-Hour					
	1987	6.01092	1989.7	-1342.1	87092110
	1988	5.58265	90.7	2598.4	88052809
	1989	5.78652	3425.8	1525.3	89051107
	1990	5.51579	746.7	-1024.1	90081212
	1991	5.51047	2587.0	1334.9	91030916
HIGH 3-Hour					
	1987	3.71006	2110.4	1690.9	87062712
	1988	3.45186	519.8	2445.4	88060815
	1989	3.30689	-2691.7	2343.7	89071515
	1990	3.23950	-2691.7	2343.7	90052815
	1991	3.60914	-4222.7	-798.3	91040406
HIGH 8-Hour					
	1987	2.42409	-3976.4	-2218.9	87110116
	1988	2.32795	-4265.2	-553.4	88013008
	1989	2.10758	-2343.6	2343.7	89060516
	1990	2.42864	-4146.2	-1239.2	90030816
	1991	2.57478	-5439.8	1904.2	91052124
HIGH 24-Hour					
	1987	1.70454	-4403.8	-29.7	87111624
	1988	1.52604	-4248.2	-651.4	88013024
	1989	0.95329	-4596.3	3856.7	89040424
	1990	1.51041	-1746.9	2343.7	90101024
	1991	1.67339	-5327.2	2343.7	91052124
SOURCE GROUP ID:	LD7559				
Annual					
	1987	0.09310	-5196.1	3000.0	87123124
	1988	0.08783	-4997.0	174.5	88123124
	1989	0.10105	-2676.5	2972.6	89123124
	1990	0.11374	-4979.6	2875.0	90123124
	1991	0.10776	-4332.6	2343.7	91123124
HIGH 1-Hour					
	1987	6.01104	1989.7	-1342.1	87092110
	1988	5.58365	90.7	2598.4	88052809

	1989	5.78754	3425.8	1525.3	89051107
	1990	5.53109	746.7	-1024.1	90081212
	1991	5.61765	2587.0	1334.9	91030916
HIGH 3-Hour					
	1987	3.78205	2110.4	1690.9	87062712
	1988	3.50631	519.8	2445.4	88060815
	1989	3.34313	-2691.7	2343.7	89071515
	1990	3.28251	-2691.7	2343.7	90052815
	1991	3.68178	-4222.7	-798.3	91040406
HIGH 8-Hour					
	1987	2.47555	-3976.4	-2218.9	87110116
	1988	2.39962	-4265.2	-553.4	88013008
	1989	2.13852	-2343.6	2343.7	89060516
	1990	2.48977	-4146.2	-1239.2	90030816
	1991	2.61516	-5416.2	1860.3	91052124
HIGH 24-Hour					
	1987	1.75051	-4403.8	-29.7	87111624
	1988	1.57074	-4248.2	-651.4	88013024
	1989	0.98243	-4596.3	3856.7	89040424
	1990	1.55468	-1746.9	2343.7	90101024
	1991	1.70066	-5327.2	2343.7	91052124
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.09830	-4979.6	2875.0	87123124
	1988	0.09213	-4997.0	174.5	88123124
	1989	0.10694	-2509.2	2786.8	89123124
	1990	0.11996	-4763.1	2750.0	90123124
	1991	0.11383	-4282.9	2343.7	91123124
HIGH 1-Hour					
	1987	6.01284	1989.7	-1342.1	87092110
	1988	5.59125	-155.6	2343.7	88052309
	1989	5.79164	3425.8	1525.3	89051107
	1990	5.78904	1957.2	-2901.6	90042308
	1991	5.80732	2189.9	1631.6	91021415
HIGH 3-Hour					
	1987	3.91215	2110.4	1690.9	87062712
	1988	3.60066	490.8	2343.7	88060815
	1989	3.40468	-2691.7	2343.7	89071515
	1990	3.36387	-4027.3	-1925.0	90022624
	1991	3.81255	-4222.7	-798.3	91040406
HIGH 8-Hour					
	1987	2.56798	-3976.4	-2218.9	87110116
	1988	2.53158	-4265.2	-553.4	88013008
	1989	2.21227	-2343.6	2343.7	89060516
	1990	2.60042	-4146.2	-1239.2	90030816
	1991	2.68737	-5416.2	1860.3	91052124
HIGH 24-Hour					
	1987	1.83368	-4403.8	-29.7	87111624
	1988	1.65276	-4248.2	-651.4	88013024
	1989	1.03771	-4404.8	3696.0	89040424
	1990	1.63620	-1746.9	2343.7	90101024
	1991	1.74896	-5327.2	2343.7	91052124
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.14050	-3984.6	2343.7	87123124
	1988	0.12982	-4497.9	146.1	88123124
	1989	0.14894	-2144.7	2343.7	89123124
	1990	0.17021	-4034.3	2343.7	90123124
	1991	0.15927	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.12469	1389.3	-1438.7	87073110
	1988	7.52947	-2940.3	2343.7	88100208
	1989	7.03941	744.6	-877.3	89092113
	1990	7.84729	-4680.7	2343.7	90071713
	1991	7.27463	2220.9	-863.9	91021514
HIGH 3-Hour					
	1987	4.82196	2110.4	1690.9	87062712
	1988	4.62181	2070.7	1720.6	88110512
	1989	4.12600	-2343.6	2343.7	89060515
	1990	4.41013	-3993.3	-2120.9	90100812
	1991	4.82224	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.42146	2070.7	1720.6	87062716
	1988	3.35803	-4265.2	-553.4	88013008

	1989	2.72800	-4163.2	-1141.2	89072516
	1990	3.30599	-4146.2	-1239.2	90030816
	1991	3.16208	-4112.3	-1435.2	91122008
HIGH 24-Hour					
	1987	2.38296	-4403.8	-29.7	87111624
	1988	2.16813	-4248.2	-651.4	88013024
	1989	1.48290	-3447.2	2892.5	89040424
	1990	2.22879	-1746.9	2343.7	90101024
	1991	2.05994	-5277.4	2343.7	91052124
SOURCE GROUP ID:	LD5059				
Annual					
	1987	0.14112	-3984.6	2343.7	87123124
	1988	0.13032	-4497.9	146.1	88123124
	1989	0.14947	-2144.7	2343.7	89123124
	1990	0.17080	-4034.3	2343.7	90123124
	1991	0.15996	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.12408	2110.4	1690.9	87012212
	1988	7.52936	-2940.3	2343.7	88100208
	1989	7.05141	744.6	-877.3	89092113
	1990	7.84949	-4680.7	2343.7	90071713
	1991	7.29542	2220.9	-863.9	91021514
HIGH 3-Hour					
	1987	4.82860	2110.4	1690.9	87062712
	1988	4.63354	2070.7	1720.6	88110512
	1989	4.13092	-2343.6	2343.7	89060515
	1990	4.41679	-3993.3	-2120.9	90100812
	1991	4.82703	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.42943	2070.7	1720.6	87062716
	1988	3.36991	-4265.2	-553.4	88013008
	1989	2.73239	-4163.2	-1141.2	89072516
	1990	3.31333	-4146.2	-1239.2	90030816
	1991	3.17139	-4112.3	-1435.2	91122008
HIGH 24-Hour					
	1987	2.38800	-4403.8	-29.7	87111624
	1988	2.17512	-4248.2	-651.4	88013024
	1989	1.48910	-3447.2	2892.5	89040424
	1990	2.23490	-1746.9	2343.7	90101024
	1991	2.06201	-5277.4	2343.7	91052124
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.14158	-3984.6	2343.7	87123124
	1988	0.13059	-4497.9	146.1	88123124
	1989	0.14906	-2144.7	2343.7	89123124
	1990	0.17118	-4034.3	2343.7	90123124
	1991	0.16005	-4183.5	2343.7	91123124
HIGH 1-Hour					
	1987	7.11985	1389.3	-1438.7	87073110
	1988	7.52847	-2940.3	2343.7	88100208
	1989	7.03989	744.6	-877.3	89092113
	1990	7.85314	-4680.7	2343.7	90071713
	1991	7.30323	2220.9	-863.9	91021514
HIGH 3-Hour					
	1987	4.82296	2110.4	1690.9	87062712
	1988	4.62592	2070.7	1720.6	88110512
	1989	4.12493	-2343.6	2343.7	89060515
	1990	4.40612	-3993.3	-2120.9	90100812
	1991	4.81284	2428.2	1453.6	91060212
HIGH 8-Hour					
	1987	3.42523	2070.7	1720.6	87062716
	1988	3.37797	-4265.2	-553.4	88013008
	1989	2.72767	-4163.2	-1141.2	89072516
	1990	3.31437	-4146.2	-1239.2	90030816
	1991	3.17726	-4112.3	-1435.2	91122008
HIGH 24-Hour					
	1987	2.38715	-4403.8	-29.7	87111624
	1988	2.17928	-4248.2	-651.4	88013024
	1989	1.49101	-3447.2	2892.5	89040424
	1990	2.23484	-1746.9	2343.7	90101024
	1991	2.06013	-5277.4	2343.7	91052124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

PM_{10} REFINED ANALYSIS
ISCST3 SUMMARY

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :coolpm.087
ISCST3 OUTPUT FILE NUMBER 2 :coolpm.088
ISCST3 OUTPUT FILE NUMBER 3 :coolpm.089
ISCST3 OUTPUT FILE NUMBER 4 :coolpm.090
ISCST3 OUTPUT FILE NUMBER 5 :coolpm.091
First title for last output file is: FPL MARTIN PROPOSED COMBINED CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, FU

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	ALL				
Annual					
	1987	0.28224	-3934.8	2343.7	87123124
	1988	0.26072	-4427.3	14.3	88123124
	1989	0.31370	-2194.4	2343.7	89123124
	1990	0.33932	-3984.6	2343.7	90123124
	1991	0.31566	-4183.5	2343.7	91123124
HIGH 24-Hour					
	1987	4.36750	-4380.2	-73.7	87111624
	1988	3.96095	-4248.2	-651.4	88013024
	1989	2.89090	-3064.2	2571.1	89040424
	1990	4.31530	-1796.6	2343.7	90101024
	1991	3.69525	-5277.4	2343.7	91052124
SOURCE GROUP ID:	LD5035				
Annual					
	1987	0.23667	-3984.6	2343.7	87123124
	1988	0.21868	-4497.9	146.1	88123124
	1989	0.25087	-2144.7	2343.7	89123124
	1990	0.28670	-4034.3	2343.7	90123124
	1991	0.26829	-4183.5	2343.7	91123124
HIGH 24-Hour					
	1987	4.01396	-4403.8	-29.7	87111624
	1988	3.65210	-4248.2	-651.4	88013024
	1989	2.49786	-3447.2	2892.5	89040424
	1990	3.75427	-1746.9	2343.7	90101024
	1991	3.46985	-5277.4	2343.7	91052124
SOURCE GROUP ID:	COOL				
Annual					
	1987	0.04937	-2940.3	2343.7	87123124
	1988	0.04776	-2741.4	2343.7	88123124
	1989	0.06533	-2393.3	2343.7	89123124
	1990	0.05799	-2592.2	2343.7	90123124
	1991	0.05653	-2045.2	2343.7	91123124
HIGH 24-Hour					
	1987	0.83634	749.5	-1219.9	87101324
	1988	0.71289	43.3	2343.7	88090524
	1989	0.63831	-1597.7	2343.7	89060924
	1990	0.70676	748.8	-1170.9	90072724
	1991	0.65222	-901.5	2343.7	91030224

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

SO_2 AAQS ANALYSIS
ISCST3 SUMMARY

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :comboil.087
ISCST3 OUTPUT FILE NUMBER 2 :comboil.088
ISCST3 OUTPUT FILE NUMBER 3 :comboil.089
ISCST3 OUTPUT FILE NUMBER 4 :comboil.090
ISCST3 OUTPUT FILE NUMBER 5 :comboil.091
First title for last output file is: FPL MARTIN PROPOSED COMBINED CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, FU

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	LD5035				
HSH 24-Hour					
	1987	6.31906	-4521.5	190.1	87123124
	1988	5.47545	-4180.2	-1043.3	88013024
	1989	4.66681	-2542.5	2343.7	89060424
	1990	6.81151	-4163.2	-1141.2	90030824
	1991	6.30369	-4265.2	-553.4	91040424
SOURCE GROUP ID:	ALL				
HSH 24-Hour					
	1987	72.97417	-4145.2	2796.0	87061924
	1988	72.18076	-3785.6	2343.7	88071124
	1989	62.52339	-4282.9	2343.7	89073124
	1990	69.05883	-4233.2	2343.7	90050424
	1991	74.02855	-3715.7	3345.6	91072424

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

SO_2 PSD CLASS II ANALYSIS
ISCST3 SUMMARY

ISCBOB3R RELEASE 00285

ISCST3 OUTPUT FILE NUMBER 1 :psdoil.O87
ISCST3 OUTPUT FILE NUMBER 2 :psdoil.O88
ISCST3 OUTPUT FILE NUMBER 3 :psdoil.O89
ISCST3 OUTPUT FILE NUMBER 4 :psdoil.O90
ISCST3 OUTPUT FILE NUMBER 5 :psdoil.O91
First title for last output file is: FPL MARTIN PROPOSED COMBINED CYCLE CTS 12/20/01
Second title for last output file is: SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, FU

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	LD5035				
HSH 24-Hour					
	1987	6.31906	-4521.5	190.1	87123124
	1988	5.47545	-4180.2	-1043.3	88013024
	1989	4.66681	-2542.5	2343.7	89060424
	1990	6.81151	-4163.2	-1141.2	90030824
	1991	6.30369	-4265.2	-553.4	91040424
SOURCE GROUP ID:	ALL				
HSH 24-Hour					
	1987	41.39065	-2741.4	2343.7	87080724
	1988	36.22301	-3830.2	3213.9	88090924
	1989	37.41634	-1995.5	2343.7	89061524
	1990	38.79645	-4061.3	-1729.1	90100924
	1991	37.97731	-4233.2	2343.7	91052124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

EXAMPLE ISCST3
INPUT FILE

```
**
****************************************
**
** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 4.03
** Lakes Environmental Software Inc.
** Date: 12/20/01
** File: D:\martin\martin1.INP
**
****************************************
**
**
****************************************
** ISCST3 Control Pathway
****************************************
**
**
CO STARTING
   TITLEONE FPL MARTIN PROPOSED COMBINED CYCLE CTS           12/20/01
   TITLETWO SIGNIFICANT IMPACT ANALYSIS, SITE VICINITY, GENERIC 10G/S, Nat. Gas
   MODELOPT DFAULT CONC NOCMPL  RURAL
   AVERTIME 1 3 8 24 PERIOD
   POLLUTID GEN
   TERRHGTS FLAT
   RUNORNOT RUN
CO FINISHED
**
****************************************
** ISCST3 Source Pathway
****************************************
**
**
SO STARTING
** Source Location **
** Source ID - Type - X Coord. - Y Coord. **
   LOCATION BSDB35A POINT -152.72 55.009
   LOCATION BSDB35B POINT -107.14 55.009
   LOCATION BSDB35C POINT 0.00000 55.009
   LOCATION BSDB35D POINT 45.7200 55.009

   LOCATION BSDB59A POINT -152.72 55.009
   LOCATION BSDB59B POINT -107.14 55.009
   LOCATION BSDB59C POINT 0.00000 55.009
   LOCATION BSDB59D POINT 45.7200 55.009

   LOCATION BSDB95A POINT -152.72 55.009
   LOCATION BSDB95B POINT -107.14 55.009
   LOCATION BSDB95C POINT 0.00000 55.009
   LOCATION BSDB95D POINT 45.7200 55.009

   LOCATION POWAUGA POINT -152.72 55.009
   LOCATION POWAUGB POINT -107.14 55.009
   LOCATION POWAUGC POINT 0.00000 55.009
   LOCATION POWAUGD POINT 45.7200 55.009

   LOCATION LD7535A POINT -152.72 55.009
   LOCATION LD7535B POINT -107.14 55.009
```

```
LOCATION LD7535C POINT 0.00000 55.009
LOCATION LD7535D POINT 45.7200 55.009

LOCATION LD7559A POINT -152.72 55.009
LOCATION LD7559B POINT -107.14 55.009
LOCATION LD7559C POINT 0.00000 55.009
LOCATION LD7559D POINT 45.7200 55.009

LOCATION LD7595A POINT -152.72 55.009
LOCATION LD7595B POINT -107.14 55.009
LOCATION LD7595C POINT 0.00000 55.009
LOCATION LD7595D POINT 45.7200 55.009

LOCATION LD5035A POINT -152.72 55.009
LOCATION LD5035B POINT -107.14 55.009
LOCATION LD5035C POINT 0.00000 55.009
LOCATION LD5035D POINT 45.7200 55.009

LOCATION LD5059A POINT -152.72 55.009
LOCATION LD5059B POINT -107.14 55.009
LOCATION LD5059C POINT 0.00000 55.009
LOCATION LD5059D POINT 45.7200 55.009

LOCATION LD5095A POINT -152.72 55.009
LOCATION LD5095B POINT -107.14 55.009
LOCATION LD5095C POINT 0.00000 55.009
LOCATION LD5095D POINT 45.7200 55.009

** Source Parameters **
SRCPARAM BSDB35A 2.25 36.576 360 18.6 5.7912
SRCPARAM BSDB35B 2.25 36.576 360 18.6 5.7912
SRCPARAM BSDB35C 2.25 36.576 360 18.6 5.7912
SRCPARAM BSDB35D 2.25 36.576 360 18.6 5.7912

SRCPARAM BSDB59A 2.25 36.576 360 17.8 5.7912
SRCPARAM BSDB59B 2.25 36.576 360 17.8 5.7912
SRCPARAM BSDB59C 2.25 36.576 360 17.8 5.7912
SRCPARAM BSDB59D 2.25 36.576 360 17.8 5.7912

SRCPARAM BSDB95A 2.25 36.576 361 16.5 5.7912
SRCPARAM BSDB95B 2.25 36.576 361 16.5 5.7912
SRCPARAM BSDB95C 2.25 36.576 361 16.5 5.7912
SRCPARAM BSDB95D 2.25 36.576 361 16.5 5.7912

SRCPARAM POWAUGA 2.25 36.576 369 17.6 5.7912
SRCPARAM POWAUGB 2.25 36.576 369 17.6 5.7912
SRCPARAM POWAUGC 2.25 36.576 369 17.6 5.7912
SRCPARAM POWAUGD 2.25 36.576 369 17.6 5.7912

SRCPARAM LD7535A 2.25 36.576 359 14.7 5.7912
SRCPARAM LD7535B 2.25 36.576 359 14.7 5.7912
SRCPARAM LD7535C 2.25 36.576 359 14.7 5.7912
SRCPARAM LD7535D 2.25 36.576 359 14.7 5.7912

SRCPARAM LD7559A 2.25 36.576 360 14.4 5.7912
SRCPARAM LD7559B 2.25 36.576 360 14.4 5.7912
SRCPARAM LD7559C 2.25 36.576 360 14.4 5.7912
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   SRCPARAM LD7559D 2.25 36.576 360 14.4 5.7912

   SRCPARAM LD7595A 2.25 36.576 361 13.5 5.7912
   SRCPARAM LD7595B 2.25 36.576 361 13.5 5.7912
   SRCPARAM LD7595C 2.25 36.576 361 13.5 5.7912
   SRCPARAM LD7595D 2.25 36.576 361 13.5 5.7912

   SRCPARAM LD5035A 2.25 36.576 353 11.9 5.7912
   SRCPARAM LD5035B 2.25 36.576 353 11.9 5.7912
   SRCPARAM LD5035C 2.25 36.576 353 11.9 5.7912
   SRCPARAM LD5035D 2.25 36.576 353 11.9 5.7912

   SRCPARAM LD5059A 2.25 36.576 354 11.7 5.7912
   SRCPARAM LD5059B 2.25 36.576 354 11.7 5.7912
   SRCPARAM LD5059C 2.25 36.576 354 11.7 5.7912
   SRCPARAM LD5059D 2.25 36.576 354 11.7 5.7912

   SRCPARAM LD5095A 2.25 36.576 353 11.4 5.7912
   SRCPARAM LD5095B 2.25 36.576 353 11.4 5.7912
   SRCPARAM LD5095C 2.25 36.576 353 11.4 5.7912
   SRCPARAM LD5095D 2.25 36.576 353 11.4 5.7912

** Building Downwash **
   BUILDHGT BSDB35A-BSDB95A 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35A-BSDB95A 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35A-BSDB95A 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35A-BSDB95A 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35A-BSDB95A 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35A-BSDB95A 25.30 25.30 25.30 25.30 25.30 25.30
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   BUILDHGT BSDB35C-BSDB95C 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35C-BSDB95C 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35C-BSDB95C 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35C-BSDB95C 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35C-BSDB95C 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35C-BSDB95C 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35D-BSDB95D 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35D-BSDB95D 25.30 25.30 25.30 25.30 25.30 25.30
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   BUILDHGT BSDB35D-BSDB95D 25.30 25.30 25.30 25.30 25.30 25.30
   BUILDHGT BSDB35D-BSDB95D 25.30 25.30 25.30 25.30 25.30 25.30

   BUILDWID BSDB35A-BSDB95A 13.25 16.64 19.53 21.83 23.46 24.38
   BUILDWID BSDB35A-BSDB95A 24.56 24.00 22.70 24.00 24.57 24.39
   BUILDWID BSDB35A-BSDB95A 23.47 21.83 19.53 16.64 13.25 9.45
   BUILDWID BSDB35A-BSDB95A 13.25 16.64 19.53 21.83 23.46 24.38
   BUILDWID BSDB35A-BSDB95A 24.56 24.00 22.70 24.00 24.57 24.39
   BUILDWID BSDB35A-BSDB95A 23.47 21.83 19.53 16.64 13.25 9.45
   BUILDWID BSDB35B-BSDB95B 13.25 16.64 19.53 21.83 23.46 24.38
   BUILDWID BSDB35B-BSDB95B 24.56 24.00 22.70 24.00 24.57 24.39
   BUILDWID BSDB35B-BSDB95B 23.47 21.83 19.54 16.64 13.25 9.45
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BUILDWID BSDB35B-BSDB95B 13.25 16.64 19.53 21.83 23.46 24.38
BUILDWID BSDB35B-BSDB95B 24.56 24.00 22.70 24.00 24.57 24.39
BUILDWID BSDB35B-BSDB95B 23.47 21.83 19.54 16.64 13.25 9.45
BUILDWID BSDB35C-BSDB95C 13.25 16.65 19.54 21.83 23.46 24.38
BUILDWID BSDB35C-BSDB95C 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID BSDB35C-BSDB95C 23.46 21.83 19.53 16.64 13.25 9.45
BUILDWID BSDB35C-BSDB95C 13.25 16.65 19.54 21.83 23.46 24.38
BUILDWID BSDB35C-BSDB95C 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID BSDB35C-BSDB95C 23.46 21.83 19.53 16.64 13.25 9.45
BUILDWID BSDB35D-BSDB95D 13.25 16.65 19.54 21.83 23.46 24.38
BUILDWID BSDB35D-BSDB95D 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID BSDB35D-BSDB95D 23.46 21.83 19.53 16.64 13.25 9.45
BUILDWID BSDB35D-BSDB95D 13.25 16.65 19.54 21.83 23.46 24.38
BUILDWID BSDB35D-BSDB95D 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID BSDB35D-BSDB95D 23.46 21.83 19.53 16.64 13.25 9.45

BUILDHGT POWAUGA 25.30 25.30 25.30 25.30 25.30 25.30
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BUILDWID LD7535D-LD7595D 24.56 24.00 22.70 24.00 24.56 24.38
BUILDWID LD7535D-LD7595D 23.46 21.83 19.53 16.64 13.25 9.45
BUILDWID LD7535D-LD7595D 13.25 16.65 19.54 21.83 23.46 24.38
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BUILDWID LD7535D-LD7595D 23.46 21.83 19.53 16.64 13.25 9.45

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BUILDWID LD5035A-LD5095A 13.25 16.64 19.53 21.83 23.46 24.38
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BUILDWID LD5035D-LD5095D 23.46 21.83 19.53 16.64 13.25 9.45

CONCUNIT 1000000 (GRAMS/SEC) (MICROGRAMS/CUBIC-METER)

SRCGROUP BSDB35   BSDB35A BSDB35B BSDB35C BSDB35D
SRCGROUP BSDB59   BSDB59A BSDB59B BSDB59C BSDB59D
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   SRCGROUP BSDB95   BSDB95A BSDB95B BSDB95C BSDB95D
   SRCGROUP POWAUG   POWAUGA POWAUGB POWAUGC POWAUGD
   SRCGROUP LD7535   LD7535A LD7535B LD7535C LD7535D
   SRCGROUP LD7559   LD7559A LD7559B LD7559C LD7559D
   SRCGROUP LD7595   LD7595A LD7595B LD7595C LD7595D
   SRCGROUP LD5035   LD5035A LD5035B LD5035C LD5035D
   SRCGROUP LD5059   LD5059A LD5059B LD5059C LD5059D
   SRCGROUP LD5095   LD5095A LD5095B LD5095C LD5095D


SO FINISHED
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** ISCST3 Receptor Pathway
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RE STARTING
   DISCCART 0.00 2400.00
   DISCCART 0.00 2500.00
   DISCCART 0.00 2600.00
   DISCCART 0.00 2700.00
   DISCCART 0.00 2800.00
   DISCCART 0.00 2900.00
   DISCCART 83.76 2398.54
   DISCCART 87.25 2498.48
   DISCCART 90.74 2598.42
   DISCCART 94.23 2698.36
   DISCCART 97.72 2798.29
   DISCCART 101.21 2898.23
   DISCCART 167.42 2394.15
   DISCCART 174.39 2493.91
   DISCCART 181.37 2593.67
   DISCCART 188.34 2693.42
   DISCCART 195.32 2793.18
   DISCCART 202.29 2892.94
   DISCCART 250.87 2386.85
   DISCCART 261.32 2486.30
   DISCCART 271.77 2585.76
   DISCCART 282.23 2685.21
   DISCCART 292.68 2784.66
   DISCCART 303.13 2884.11
   DISCCART 334.02 2376.64
   DISCCART 347.93 2475.67
   DISCCART 361.85 2574.70
   DISCCART 375.77 2673.72
   DISCCART 389.68 2772.75
   DISCCART 403.60 2871.78
   DISCCART 416.76 2363.54
   DISCCART 434.12 2462.02
   DISCCART 451.49 2560.50
   DISCCART 468.85 2658.98
   DISCCART 486.21 2757.46
   DISCCART 503.58 2855.94
   DISCCART 498.99 2347.55
   DISCCART 519.78 2445.37
   DISCCART 540.57 2543.18
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DISCCART	561.36	2641.00
DISCCART	582.15	2738.81
DISCCART	602.94	2836.63
DISCCART	604.80	2425.74
DISCCART	629.00	2522.77
DISCCART	653.19	2619.80
DISCCART	677.38	2716.83
DISCCART	701.57	2813.86
DISCCART	689.09	2403.15
DISCCART	716.66	2499.28
DISCCART	744.22	2595.41
DISCCART	771.78	2691.53
DISCCART	799.35	2787.66
DISCCART	772.54	2377.64
DISCCART	803.44	2472.75
DISCCART	834.35	2567.85
DISCCART	865.25	2662.96
DISCCART	896.15	2758.06
DISCCART	855.05	2349.23
DISCCART	889.25	2443.20
DISCCART	923.45	2537.17
DISCCART	957.66	2631.14
DISCCART	991.86	2725.11
DISCCART	973.98	2410.68
DISCCART	1011.44	2503.40
DISCCART	1048.90	2596.11
DISCCART	1086.36	2688.83
DISCCART	1057.52	2375.22
DISCCART	1098.19	2466.57
DISCCART	1138.86	2557.93
DISCCART	1179.54	2649.28
DISCCART	1183.60	2426.74
DISCCART	1227.44	2516.62
DISCCART	1271.28	2606.50
DISCCART	1267.57	2383.96
DISCCART	1314.52	2472.25
DISCCART	1361.47	2560.55
DISCCART	1350.00	2338.27
DISCCART	1400.00	2424.87
DISCCART	1450.00	2511.47
DISCCART	1430.78	2289.73
DISCCART	1483.77	2374.53
DISCCART	1536.77	2459.34
DISCCART	1509.82	2238.40
DISCCART	1565.74	2321.31
DISCCART	1621.66	2404.21
DISCCART	1587.02	2184.35
DISCCART	1645.80	2265.25
DISCCART	1704.58	2346.15
DISCCART	1662.29	2127.63
DISCCART	1723.85	2206.43
DISCCART	1785.42	2285.23
DISCCART	1735.53	2068.32
DISCCART	1799.81	2144.92
DISCCART	1864.08	2221.53
DISCCART	1806.65	2006.49
DISCCART	1873.57	2080.81

DISCCART	1940.48	2155.12
DISCCART	1875.58	1942.22
DISCCART	1945.04	2014.15
DISCCART	2014.51	2086.09
DISCCART	1942.22	1875.58
DISCCART	2014.15	1945.04
DISCCART	2086.09	2014.51
DISCCART	2006.49	1806.65
DISCCART	2080.81	1873.57
DISCCART	2155.12	1940.48
DISCCART	2068.32	1735.53
DISCCART	2144.92	1799.81
DISCCART	2221.53	1864.08
DISCCART	2206.43	1723.85
DISCCART	2285.23	1785.42
DISCCART	2265.25	1645.80
DISCCART	2346.15	1704.58
DISCCART	2321.31	1565.74
DISCCART	2404.21	1621.66
DISCCART	2459.34	1536.77
DISCCART	2511.47	1450.00
DISCCART	2560.55	1361.47
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DISCCART	2758.06	-896.15
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DISCCART	2537.17	-923.45
DISCCART	2631.14	-957.66
DISCCART	2725.11	-991.86
DISCCART	2225.24	-899.06
DISCCART	2317.96	-936.52
DISCCART	2410.68	-973.98
DISCCART	2503.40	-1011.44
DISCCART	2596.11	-1048.90
DISCCART	2688.83	-1086.36
DISCCART	2009.80	-894.82
DISCCART	2101.15	-935.49
DISCCART	2192.51	-976.17
DISCCART	2283.86	-1016.84
DISCCART	2375.22	-1057.52
DISCCART	2466.57	-1098.19
DISCCART	2557.93	-1138.86
DISCCART	2649.28	-1179.54
DISCCART	1797.59	-876.74
DISCCART	1887.47	-920.58
DISCCART	1977.35	-964.42
DISCCART	2067.23	-1008.25
DISCCART	2157.11	-1052.09
DISCCART	2246.99	-1095.93
DISCCART	2336.86	-1139.76
DISCCART	2426.74	-1183.60
DISCCART	2516.62	-1227.44
DISCCART	2606.50	-1271.28
DISCCART	1677.60	-892.00
DISCCART	1765.90	-938.94
DISCCART	1854.19	-985.89
DISCCART	1942.48	-1032.84
DISCCART	2030.78	-1079.78

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DISCCART 2207.37 -1173.68
DISCCART 2295.66 -1220.63
DISCCART 2383.96 -1267.57
DISCCART 2472.25 -1314.52
DISCCART 2560.55 -1361.47
DISCCART 1558.85 -900.00
DISCCART 1645.45 -950.00
DISCCART 1732.05 -1000.00
DISCCART 1818.65 -1050.00
DISCCART 1905.26 -1100.00
DISCCART 1991.86 -1150.00
DISCCART 2078.46 -1200.00
DISCCART 2165.06 -1250.00
DISCCART 2251.67 -1300.00
DISCCART 2338.27 -1350.00
DISCCART 2424.87 -1400.00
DISCCART 2511.47 -1450.00
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ALL RECEPTORS NOT SHOWN DUE TO LENGTH OF FILE, SEE ELECTRONIC VERSION FOR ALL RECEPTORS

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DISCCART -12500.00 -21650.64
DISCCART -15000.00 -25980.76
DISCCART -7948.79 -12720.72
DISCCART -10598.39 -16960.96
DISCCART -13247.98 -21201.20
DISCCART -15897.58 -25441.44
DISCCART -8387.89 -12435.56
DISCCART -11183.86 -16580.75
DISCCART -13979.82 -20725.94
DISCCART -16775.79 -24871.13
DISCCART -8816.78 -12135.25
DISCCART -11755.71 -16180.34
DISCCART -14694.63 -20225.42
DISCCART -17633.56 -24270.51
DISCCART -9234.92 -11820.16
DISCCART -12313.23 -15760.22
DISCCART -15391.54 -19700.27
DISCCART -18469.84 -23640.32
DISCCART -9641.81 -11490.67
DISCCART -12855.75 -15320.89
DISCCART -16069.69 -19151.11
DISCCART -19283.63 -22981.33
DISCCART -10036.96 -11147.17
DISCCART -13382.61 -14862.90
DISCCART -16728.27 -18578.62
DISCCART -20073.92 -22294.34
DISCCART -10419.88 -10790.10
DISCCART -13893.17 -14386.80
DISCCART -17366.46 -17983.50
DISCCART -20839.75 -21580.19
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DISCCART -21580.19 -20839.75
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   DISCCART -2087.60 14854.02
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   DISCCART -3479.33 24756.70
   DISCCART -4175.19 29708.04
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   DISCCART -2613.21 24863.05
   DISCCART -3135.85 29835.66
   DISCCART -1046.35 14963.46
   DISCCART -1395.13 19951.28
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   DISCCART -2092.69 29926.92
   DISCCART -523.49 14990.86
   DISCCART -697.99 19987.82
   DISCCART -872.49 24984.77
   DISCCART -1046.98 29981.72
** Discrete Cartesian Plant Boundary - Primary Receptors
   DISCCART -5675.24 2343.74
   DISCCART 1236.69 2343.74
   DISCCART 3182.77 889.78
   DISCCART 3205.14 -854.98
   DISCCART 744.58 -877.35
   DISCCART 766.95 -2443.16
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DISCCART	-3891.41	-2708.75
DISCCART	-3899.90	-2659.77
DISCCART	-3908.40	-2610.78
DISCCART	-3916.89	-2561.80
DISCCART	-3925.39	-2512.81
DISCCART	-3933.88	-2463.83
DISCCART	-3942.38	-2414.85
DISCCART	-3950.87	-2365.86
DISCCART	-3959.37	-2316.88
DISCCART	-3967.86	-2267.89
DISCCART	-3976.35	-2218.91
DISCCART	-3984.85	-2169.92
DISCCART	-3993.34	-2120.94
DISCCART	-4001.84	-2071.95
DISCCART	-4010.33	-2022.97
DISCCART	-4018.83	-1973.98
DISCCART	-4027.32	-1925.00
DISCCART	-4035.81	-1876.01
DISCCART	-4044.31	-1827.03
DISCCART	-4052.80	-1778.04
DISCCART	-4061.30	-1729.06
DISCCART	-4069.79	-1680.08
DISCCART	-4078.29	-1631.09
DISCCART	-4086.78	-1582.11
DISCCART	-4095.28	-1533.12
DISCCART	-4103.77	-1484.14
DISCCART	-4112.26	-1435.15
DISCCART	-4120.76	-1386.17
DISCCART	-4129.25	-1337.18
DISCCART	-4137.75	-1288.20
DISCCART	-4146.24	-1239.21
DISCCART	-4154.74	-1190.23
DISCCART	-4163.23	-1141.24
DISCCART	-4171.73	-1092.26
DISCCART	-4180.22	-1043.27
DISCCART	-4188.71	-994.29
DISCCART	-4197.21	-945.30
DISCCART	-4205.70	-896.32
DISCCART	-4214.20	-847.34
DISCCART	-4222.69	-798.35

DISCCART	-4231.19	-749.37
DISCCART	-4239.68	-700.38
DISCCART	-4248.18	-651.40
DISCCART	-4256.67	-602.41
DISCCART	-4265.16	-553.43
DISCCART	-4273.66	-504.44
DISCCART	-4282.15	-455.46
DISCCART	-4290.65	-406.47
DISCCART	-4299.14	-357.49
DISCCART	-4307.64	-308.50
DISCCART	-4316.13	-259.52
DISCCART	-4324.63	-210.53
DISCCART	-4356.67	-117.60
DISCCART	-4380.21	-73.65
DISCCART	-4403.76	-29.69
DISCCART	-4427.30	14.26
DISCCART	-4450.85	58.21
DISCCART	-4474.40	102.16
DISCCART	-4497.94	146.12
DISCCART	-4521.49	190.07
DISCCART	-4545.03	234.02
DISCCART	-4568.58	277.97
DISCCART	-4592.13	321.93
DISCCART	-4615.67	365.88
DISCCART	-4639.22	409.83
DISCCART	-4662.76	453.78
DISCCART	-4686.31	497.74
DISCCART	-4709.86	541.69
DISCCART	-4733.40	585.64
DISCCART	-4756.95	629.59
DISCCART	-4780.49	673.55
DISCCART	-4804.04	717.50
DISCCART	-4827.59	761.45
DISCCART	-4851.13	805.40
DISCCART	-4874.68	849.36
DISCCART	-4898.22	893.31
DISCCART	-4921.77	937.26
DISCCART	-4945.32	981.21
DISCCART	-4968.86	1025.17
DISCCART	-4992.41	1069.12
DISCCART	-5015.95	1113.07
DISCCART	-5039.50	1157.02
DISCCART	-5063.04	1200.98
DISCCART	-5086.59	1244.93
DISCCART	-5110.14	1288.88
DISCCART	-5133.68	1332.83
DISCCART	-5157.23	1376.79
DISCCART	-5180.77	1420.74
DISCCART	-5204.32	1464.69
DISCCART	-5227.87	1508.64
DISCCART	-5251.41	1552.60
DISCCART	-5274.96	1596.55
DISCCART	-5298.50	1640.50
DISCCART	-5322.05	1684.45
DISCCART	-5345.60	1728.41
DISCCART	-5369.14	1772.36
DISCCART	-5392.69	1816.31

```
   DISCCART -5416.23 1860.26
   DISCCART -5439.78 1904.22
   DISCCART -5463.33 1948.17
   DISCCART -5486.87 1992.12
   DISCCART -5510.42 2036.07
   DISCCART -5533.96 2080.03
   DISCCART -5557.51 2123.98
   DISCCART -5581.06 2167.93
   DISCCART -5604.60 2211.88
   DISCCART -5628.15 2255.84
   DISCCART -5651.69 2299.79
RE FINISHED
**
****************************************
** ISCST3 Meteorology Pathway
****************************************
**
**
ME STARTING
** Met File Path: d:\MET\
   INPUTFIL d:\met\PBIPBI87.MET
   ANEMHGHT 33 FEET
   SURFDATA 12844 1987 WEST-PALM-BCH
   UAIRDATA 12844 1987 WEST-PALM-BCH
ME FINISHED
**
****************************************
** ISCST3 Output Pathway
****************************************
**
**
OU STARTING
   RECTABLE ALLAVE FIRST
   RECTABLE 1 FIRST
   RECTABLE 3 FIRST
   RECTABLE 8 FIRST
   RECTABLE 24 FIRST
** Auto-Generated Plotfiles
** Plotfile Path: D:\martin\martin1.IS\

OU FINISHED
```

EXAMPLE CALPUFF
INPUT FILE

```
FPL MARTIN PROPOSED CTS, COMBINED CYCLE, FUEL OIL, BASE LOAD, 35DEG F
FOR SIGNIFICANT IMPACT ANALYSIS AND AQRV ANALYSES AT EVERGLADES NATIONAL PARK
REFINED CALPUFF ANALYSIS USING SOUTH FLORIDA CALMET DOMAIN
---------------- Run title (3 lines) ------------------------------------------

              CALPUFF MODEL CONTROL FILE
              --------------------------


-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names

   Number of CALMET.DAT files for run (NMETDAT)
                         Default: 1      ! NMETDAT =   6  !

---------------
Default Name  Type        File Name
------------  ----        ---------
CALMET.DAT    input    * METDAT =         *
   or
ISCMET.DAT    input    * ISCDAT =         *
   or
PLMMET.DAT    input    * PLMDAT =         *
   or
PROFILE.DAT   input    * PRFDAT =         *
SURFACE.DAT   input    * SFCDAT =         *
RESTARTB.DAT  input    * RSTARTB=         *
-------------------------------------------------------------------------------
CALPUFF.LST   output   ! PUFLST =PUFFFOCC.LST  !
CONC.DAT      output   ! CONDAT =PUFFFOCC.CON  !
DFLX.DAT      output   ! DFDAT  =PUFFFOCC.DRY  !
WFLX.DAT      output   ! WFDAT  =PUFFFOCC.WET  !

VISB.DAT      output   ! VISDAT =VISB.DAT  !
RESTARTE.DAT  output   * RSTARTE=         *
-------------------------------------------------------------------------------
Emission Files
---------------
PTEMARB.DAT   input    * PTDAT  =         *
VOLEM.DAT     input    * VOLDAT =         *
BAEMARB.DAT   input    * ARDAT  =         *
LNEMARB.DAT   input    * LNDAT  =         *
-------------------------------------------------------------------------------
Other Files
-----------
OZONE.DAT     input    ! OZDAT  =O3ENP90.DAT  !
VD.DAT        input    * VDDAT  =         *
CHEM.DAT      input    * CHEMDAT=         *
HILL.DAT      input    * HILDAT=          *
HILLRCT.DAT   input    * RCTDAT=          *
COASTLN.DAT   input    * CSTDAT=          *
FLUXBDY.DAT   input    * BDYDAT=          *
DEBUG.DAT     output   * DEBUG =          *
MASSFLX.DAT   output   * FLXDAT=          *
MASSBAL.DAT   output   * BALDAT=          *
-------------------------------------------------------------------------------
All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
```

```
      T = lower case     ! LCFILES = T !
      F = UPPER CASE
NOTE: (1) file/path names can be up to 70 characters in length

!END!

.............
Subgroup (0a)
.............

 The following CALMET.DAT filenames are processed in sequence if NMETDAT>1

Default Name  Type        File Name
............ ....        ........
 none       input   ! METDAT=E:\CALMET\ENP\MET0102.DAT    ! !END!
 none       input   ! METDAT=E:\CALMET\ENP\MET0304.DAT    ! !END!
 none       input   ! METDAT=E:\CALMET\ENP\MET0506.DAT    ! !END!
 none       input   ! METDAT=E:\CALMET\ENP\MET0708.DAT    ! !END!
 none       input   ! METDAT=E:\CALMET\ENP\MET0910.DAT    ! !END!
 none       input   ! METDAT=E:\CALMET\ENP\MET1112.DAT    ! !END!

..............................................................................

INPUT GROUP: 1 -- General run control parameters
..............

   Option to run all periods found
   in the met. file     (METRUN)   Default: 0       ! METRUN =   0  !

       METRUN = 0 - Run period explicitly defined below
       METRUN = 1 - Run all periods in met. file

    Starting date:   Year (IBYR) -- No default        ! IBYR =  1990  !
    (used only if   Month (IBMO) -- No default       ! IBMO =  1  !
     METRUN = 0)       Day (IBDY) -- No default       ! IBDY =  6  !
                 Hour (IBHR) -- No default       ! IBHR =  0  !

    Length of run (hours) (IRLG) -- No default       ! IRLG =  8616  !

    Number of chemical species (NSPEC)
                                 Default: 5       ! NSPEC =  7   !

    Number of chemical species
    to be emitted  (NSE)          Default: 3       ! NSE =  4   !

    Flag to stop run after
    SETUP phase (ITEST)           Default: 2       ! ITEST =  2   !
    (Used to allow checking
    of the model inputs, files, etc.)
         ITEST = 1 - STOPS program after SETUP phase
         ITEST = 2 - Continues with execution of program
                   after SETUP

    Restart Configuration:

      Control flag (MRESTART)      Default: 0       ! MRESTART =  0   !
```

```
         0 = Do not read or write a restart file
         1 = Read a restart file at the beginning of
             the run
         2 = Write a restart file during run
         3 = Read a restart file at beginning of run
             and write a restart file during run

       Number of periods in Restart
       output cycle (NRESPD)       Default: 0      ! NRESPD =  0  !

         0 = File written only at last period
        >0 = File updated every NRESPD periods

     Meteorological Data Format (METFM)
                                   Default: 1      ! METFM =  1  !

         METFM = 1 - CALMET binary file (CALMET.MET)
         METFM = 2 - ISC ASCII file (ISCMET.MET)
         METFM = 3 - AUSPLUME ASCII file (PLMMET.MET)
         METFM = 4 - CTDM plus tower file (PROFILE.DAT) and
                     surface parameters file (SURFACE.DAT)

     PG sigma-y is adjusted by the factor (AVET/PGTIME)**0.2
     Averaging Time (minutes) (AVET)
                                   Default: 60.0   ! AVET = 60. !
     PG Averaging Time (minutes) (PGTIME)
                                   Default: 60.0   ! PGTIME = 60. !


!END!


-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Technical options
--------------


     Vertical distribution used in the
     near field (MGAUSS)                  Default: 1     ! MGAUSS =  1  !
        0 = uniform
        1 = Gaussian

     Terrain adjustment method
     (MCTADJ)                        Default: 3     ! MCTADJ =  3  !
        0 = no adjustment
        1 = ISC-type of terrain adjustment
        2 = simple, CALPUFF-type of terrain
            adjustment
        3 = partial plume path adjustment

     Subgrid-scale complex terrain
     flag (MCTSG)                     Default: 0     ! MCTSG =  0  !
        0 = not modeled
        1 = modeled

     Near-field puffs modeled as
     elongated 0 (MSLUG)                  Default: 0     ! MSLUG =  0  !
```

```
  0 = no
  1 = yes (slug model used)

Transitional plume rise modeled ?
(MTRANS)                    Default: 1    ! MTRANS =  1  !
  0 = no  (i.e., final rise only)
  1 = yes (i.e., transitional rise computed)

Stack tip downwash? (MTIP)         Default: 1    ! MTIP =  1  !
  0 = no  (i.e., no stack tip downwash)
  1 = yes (i.e., use stack tip downwash)

Vertical wind shear modeled above
stack top? (MSHEAR)              Default: 0    ! MSHEAR =  1  !
  0 = no  (i.e., vertical wind shear not modeled)
  1 = yes (i.e., vertical wind shear modeled)

Puff splitting allowed? (MSPLIT)     Default: 0    ! MSPLIT =  0  !
  0 = no (i.e., puffs not split)
  1 = yes (i.e., puffs are split)

Chemical mechanism flag (MCHEM)      Default: 1    ! MCHEM =  1  !
  0 = chemical transformation not
      modeled
  1 = transformation rates computed
      internally (MESOPUFF II scheme)
  2 = user-specified transformation
      rates used
  3 = transformation rates computed
      internally (RIVAD/ARM3 scheme)

Wet removal modeled ? (MWET)        Default: 1    ! MWET =  1  !
  0 = no
  1 = yes

Dry deposition modeled ? (MDRY)      Default: 1    ! MDRY =  1  !
  0 = no
  1 = yes
  (dry deposition method specified
   for each species in Input Group 3)

Method used to compute dispersion
coefficients (MDISP)              Default: 3    ! MDISP =  4  !

  1 = dispersion coefficients computed from measured values
      of turbulence, sigma v, sigma w
  2 = dispersion coefficients from internally calculated
      sigma v, sigma w using micrometeorological variables
      (u*, w*, L, etc.)
  3 = PG dispersion coefficients for RURAL areas (computed using
      the ISCST multi-segment approximation) and MP coefficients in
      urban areas
  4 = same as 3 except PG coefficients computed using
      the MESOPUFF II eqns.
  5 = CTDM sigmas used for stable and neutral conditions.
      For unstable conditions, sigmas are computed as in
      MDISP = 3, described above.  MDISP = 5 assumes that
      measured values are read
```

```
Sigma-v/sigma-theta, sigma-w measurements used? (MTURBVW)
(Used only if MDISP = 1 or 5)       Default: 3    ! MTURBVW =  0  !
  1 = use sigma-v or sigma-theta measurements
      from PROFILE.DAT to compute sigma-y
      (valid for METFM = 1, 2, 3, 4)
  2 = use sigma-w measurements
      from PROFILE.DAT to compute sigma-z
      (valid for METFM = 1, 2, 3, 4)
  3 = use both sigma-(v/theta) and sigma-w
      from PROFILE.DAT to compute sigma-y and sigma-z
      (valid for METFM = 1, 2, 3, 4)
  4 = use sigma-theta measurements
      from PLMMET.DAT to compute sigma-y
      (valid only if METFM = 3)

Back-up method used to compute dispersion
when measured turbulence data are
missing (MDISP2)                Default: 3    ! MDISP2 =  4  !
(used only if MDISP = 1 or 5)
  2 = dispersion coefficients from internally calculated
      sigma v, sigma w using micrometeorological variables
      (u*, w*, L, etc.)
  3 = PG dispersion coefficients for RURAL areas (computed using
      the ISCST multi-segment approximation) and MP coefficients in
      urban areas
  4 = same as 3 except PG coefficients computed using
      the MESOPUFF II eqns.

PG sigma-y,z adj. for roughness?     Default: 0    ! MROUGH =  0  !
(MROUGH)
  0 = no
  1 = yes

Partial plume penetration of        Default: 1    ! MPARTL =  1  !
elevated inversion?
(MPARTL)
  0 = no
  1 = yes

Strength of temperature inversion    Default: 0    ! MTINV =  0  !
provided in PROFILE.DAT extended records?
(MTINV)
  0 = no (computed from measured/default gradients)
  1 = yes

PDF used for dispersion under convective conditions?
                              Default: 0    ! MPDF =  0  !
(MPDF)
  0 = no
  1 = yes

Sub-Grid TIBL module used for shore line?
                              Default: 0    ! MSGTIBL = 0  !
(MSGTIBL)
  0 = no
  1 = yes
```

```
   Test options specified to see if
   they conform to regulatory
   values? (MREG)              Default: 1     ! MREG =  0  !

     0 = NO checks are made
     1 = Technical options must conform to USEPA values
              METFM   1
              AVET    60. (min)
              MGAUSS  1
              MCTADJ  3
              MTRANS  1
              MTIP    1
              MCHEM   1 (if modeling SOx, NOx)
              MWET    1
              MDRY    1
              MDISP   3
              MROUGH  0
              MPARTL  1
              SYTDEP  550. (m)
              MHFTSZ  0


!END!


-------------------------------------------------------------------------------

INPUT GROUP: 3a, 3b -- Species list
-------------------

------------
Subgroup (3a)
------------

  The following species are modeled:

! CSPEC =       SO2 !      !END!
! CSPEC =       SO4 !      !END!
! CSPEC =       NOX !      !END!
! CSPEC =      HNO3 !      !END!
! CSPEC =       NO3 !      !END!
! CSPEC =      PM10 !      !END!
! CSPEC =        CO !      !END!

                                            Dry              OUTPUT GROUP
   SPECIES      MODELED       EMITTED     DEPOSITED            NUMBER
    NAME      (0=NO, 1=YES)  (0=NO, 1=YES)  (0=NO,            (0=NONE,
  (Limit: 12                              1=COMPUTED-GAS      1=1st CGRUP,
   Characters                             2=COMPUTED-PARTICLE  2=2nd CGRUP,
   in length)                             3=USER-SPECIFIED)    3= etc.)

!       SO2  =      1,         1,        1,          0  !
!       SO4  =      1,         0,        2,          0  !
!       NOX  =      1,         1,        1,          0  !
!      HNO3  =      1,         0,        1,          0  !
!       NO3  =      1,         0,        2,          0  !
!      PM10  =      1,         1,        2,          0  !
!        CO  =      1,         1,        0,          0  !
```

!END!

```
-------------
Subgroup (3b)
-------------
  The following names are used for Species-Groups in which results
  for certain species are combined (added) prior to output.  The
  CGRUP name will be used as the species name in output files.
  Use this feature to model specific particle-size distributions
  by treating each size-range as a separate species.
  Order must be consistent with 3(a) above.



-------------------------------------------------------------------------------


INPUT GROUP: 4 -- Grid control parameters
--------------


METEOROLOGICAL grid:

        No. X grid cells (NX)      No default     ! NX =  90   !
        No. Y grid cells (NY)      No default     ! NY =  94   !
      No. vertical layers (NZ)     No default     ! NZ =  9    !

       Grid spacing (DGRIDKM)      No default     ! DGRIDKM = 5. !
                            Units: km

         Cell face heights
            (ZFACE(nz+1))      No defaults
                            Units: m
  ! ZFACE = 0., 20., 50., 100., 200., 500., 1000., 1500., 2500., 3500. !

        Reference Coordinates
       of SOUTHWEST corner of
           grid cell(1, 1):

        X coordinate (XORIGKM)     No default     ! XORIGKM = 250. !
        Y coordinate (YORIGKM)     No default     ! YORIGKM = 2628. !
                            Units: km

           UTM zone (IUTMZN)       No default     ! IUTMZN =  17   !

  Reference coordinates of CENTER
     of the domain (used in the
   calculation of solar elevation
                 angles)

        Latitude  (deg.) (XLAT)    No default     ! XLAT  = 26.  !
       Longitude (deg.) (XLONG)    No default     ! XLONG = 81.  !
        Time zone        (XTZ)     No default     ! XTZ   = 5.0  !
    (PST=8, MST=7, CST=6, EST=5)
```

Computational grid:

The computational grid is identical to or a subset of the MET. grid. The lower left (LL) corner of the computational grid is at grid point (IBCOMP, JBCOMP) of the MET. grid. The upper right (UR) corner of the computational grid is at grid point (IECOMP, JECOMP) of the MET. grid. The grid spacing of the computational grid is the same as the MET. grid.

X index of LL corner (IBCOMP) No default ! IBCOMP = 1 !
(1 <= IBCOMP <= NX)

Y index of LL corner (JBCOMP) No default ! JBCOMP = 1 !
(1 <= JBCOMP <= NY)

X index of UR corner (IECOMP) No default ! IECOMP = 90 !
(1 <= IECOMP <= NX)

Y index of UR corner (JECOMP) No default ! JECOMP = 94 !
(1 <= JECOMP <= NY)

SAMPLING GRID (GRIDDED RECEPTORS):

The lower left (LL) corner of the sampling grid is at grid point (IBSAMP, JBSAMP) of the MET. grid. The upper right (UR) corner of the sampling grid is at grid point (IESAMP, JESAMP) of the MET. grid. The sampling grid must be identical to or a subset of the computational grid. It may be a nested grid inside the computational grid. The grid spacing of the sampling grid is DGRIDKM/MESHDN.

Logical flag indicating if gridded
receptors are used (LSAMP) Default: T ! LSAMP = F !
(T=yes, F=no)

X index of LL corner (IBSAMP) No default ! IBSAMP = 0 !
(IBCOMP <= IBSAMP <= IECOMP)

Y index of LL corner (JBSAMP) No default ! JBSAMP = 0 !
(JBCOMP <= JBSAMP <= JECOMP)

X index of UR corner (IESAMP) No default ! IESAMP = 90 !
(IBCOMP <= IESAMP <= IECOMP)

Y index of UR corner (JESAMP) No default ! JESAMP = 94 !
(JBCOMP <= JESAMP <= JECOMP)

Nesting factor of the sampling
grid (MESHDN) Default: 1 ! MESHDN = 1 !
(MESHDN is an integer >= 1)

!END!

INPUT GROUP: 5 -- Output Options

```
                                 *               *
  FILE                  DEFAULT VALUE        VALUE THIS RUN
  ----                  -------------        -------------

 Concentrations (ICON)         1              ! ICON = 1  !
 Dry Fluxes (IDRY)            1              ! IDRY = 1  !
 Wet Fluxes (IWET)            1              ! IWET = 1  !
 Relative Humidity (IVIS)      1              ! IVIS = 1  !
  (relative humidity file is
   required for visibility
   analysis)
 Use data compression option in output file?
 (LCOMPRS)                  Default: T      ! LCOMPRS = F !

 *
  0 = Do not create file, 1 = create file


  DIAGNOSTIC MASS FLUX OUTPUT OPTIONS:

    Mass flux across specified boundaries
    for selected species reported hourly?
    (IMFLX)                 Default: 0      ! IMFLX = 0 !
     0 = no
     1 = yes (FLUXBDY.DAT and MASSFLX.DAT filenames
          are specified in Input Group 0)

    Mass balance for each species
    reported hourly?
    (IMBAL)                 Default: 0      ! IMBAL = 0 !
     0 = no
     1 = yes (MASSBAL.DAT filename is
        specified in Input Group 0)


  LINE PRINTER OUTPUT OPTIONS:

    Print concentrations (ICPRT)   Default: 0     ! ICPRT = 0  !
    Print dry fluxes (IDPRT)      Default: 0     ! IDPRT = 0  !
    Print wet fluxes (IWPRT)      Default: 0     ! IWPRT = 0  !
    (0 = Do not print, 1 = Print)

    Concentration print interval
    (ICFRQ) in hours            Default: 1      ! ICFRQ = 24  !
    Dry flux print interval
    (IDFRQ) in hours            Default: 1      ! IDFRQ = 1  !
    Wet flux print interval
    (IWFRQ) in hours            Default: 1      ! IWFRQ = 1  !

    Units for Line Printer Output
    (IPRTU)                 Default: 1      ! IPRTU = 3  !
             for         for
          Concentration  Deposition
      1 =     g/m**3       g/m**2/s
```

```
        2 =     mg/m**3      mg/m**2/s
        3 =     ug/m**3      ug/m**2/s
        4 =     ng/m**3      ng/m**2/s
        5 =     Odour Units

     Messages tracking progress of   Default: 1       ! IMESG =  1  !
     run written to the screen ?
     (IMESG) -- 0=no, 1=yes


   SPECIES (or GROUP for combined species) LIST FOR OUTPUT OPTIONS

             ---- CONCENTRATIONS ----  ------ DRY FLUXES ------  ------ WET FLUXES ------  -- MASS FLUX --
   SPECIES
   /GROUP       PRINTED?  SAVED ON DISK?  PRINTED?  SAVED ON DISK?  PRINTED?  SAVED ON DISK?  SAVE
   -------    ------------------------  ------------------------  ------------------------  ---------------
 !       SO2 =    0,        1,          0,        1,          0,        1,          0   !
 !       SO4 =    0,        1,          0,        1,          0,        1,          0   !
 !       NOX =    0,        1,          0,        1,          0,        1,          0   !
 !      HNO3 =    0,        1,          0,        1,          0,        1,          0   !
 !       NO3 =    0,        1,          0,        1,          0,        1,          0   !
 !      PM10 =    0,        1,          0,        1,          0,        1,          0   !
 !        CO =    0,        1,          0,        1,          0,        1,          0   !

   OPTIONS FOR PRINTING "DEBUG" QUANTITIES (much output)

     Logical for debug output
     (LDEBUG)                         Default: F     ! LDEBUG = F !

     First puff to track
     (IPFDEB)                         Default: 1     ! IPFDEB =  1  !

     Number of puffs to track
     (NPFDEB)                         Default: 1     ! NPFDEB =  1  !

     Met. period to start output
     (NN1)                            Default: 1     ! NN1 =  1   !

     Met. period to end output
     (NN2)                            Default: 10    ! NN2 =  10  !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 6a, 6b, & 6c -- Subgrid scale complex terrain inputs
-------------------------

----------------
Subgroup (6a)
----------------
     Number of terrain features (NHILL)       Default: 0     ! NHILL =  0   !

     Number of special complex terrain
     receptors  (NCTREC)                  Default: 0     ! NCTREC =  0   !
```

```
     Terrain and CTSG Receptor data for
     CTSG hills input in CTDM format ?
     (MHILL)                        No Default    ! MHILL =  0  !
     1 = Hill and Receptor data created
        by CTDM processors & read from
        HILL.DAT and HILLRCT.DAT files
     2 = Hill data created by OPTHILL &
        input below in Subgroup (6b);
        Receptor data in Subgroup (6c)

     Factor to convert horizontal dimensions  Default: 1.0  ! XHILL2M = 1. !
     to meters (MHILL=1)

     Factor to convert vertical dimensions    Default: 1.0  ! ZHILL2M = 1. !
     to meters (MHILL=1)

     X-origin of CTDM system relative to      No Default    ! XCTDMKM = 0.0E00 !
     CALPUFF coordinate system, in Kilometers (MHILL=1)

     Y-origin of CTDM system relative to      No Default    ! YCTDMKM = 0.0E00 !
     CALPUFF coordinate system, in Kilometers (MHILL=1)

! END !

---------------
Subgroup (6b)
---------------

              1 **
   HILL information


HILL    XC     YC    THETAH  ZGRID  RELIEF   EXPO 1   EXPO 2  SCALE 1   SCALE 2   AMAX1    AMA
NO.    (km)   (km)   (deg.)  (m)     (m)      (m)      (m)     (m)       (m)       (m)
----   ----   ----   ------  -----  ------   ------   ------  -------   -------   -----    -----

---------------
Subgroup (6c)
---------------

   COMPLEX TERRAIN RECEPTOR INFORMATION

                 XRCT       YRCT      ZRCT       XHH
                 (km)       (km)      (m)
                ------      -----     ------     ----


-------------------
1
   Description of Complex Terrain Variables:
      XC, YC  = Coordinates of center of hill
      THETAH  = Orientation of major axis of hill (clockwise from
                North)
      ZGRID   = Height of the  0  of the grid above mean sea
                level
      RELIEF  = Height of the crest of the hill above the grid elevation
      EXPO 1  = Hill-shape exponent for the major axis
      EXPO 2  = Hill-shape exponent for the major axis
```

```
    SCALE 1 = Horizontal length scale along the major axis
    SCALE 2 = Horizontal length scale along the minor axis
    AMAX    = Maximum allowed axis length for the major axis
    BMAX    = Maximum allowed axis length for the major axis

    XRCT, YRCT = Coordinates of the complex terrain receptors
    ZRCT    = Height of the ground (MSL) at the complex terrain
              Receptor
    XHH     = Hill number associated with each complex terrain receptor
              (NOTE: MUST BE ENTERED AS A REAL NUMBER)

 **
  NOTE: DATA for each hill and CTSG receptor are treated as a separate
        input subgroup and therefore must end with an input group terminator.

------------------------------------------------------------------------------


INPUT GROUP: 7 -- Chemical parameters for dry deposition of gases
--------------

    SPECIES  DIFFUSIVITY   ALPHA STAR   REACTIVITY  MESOPHYLL RESISTANCE   HENRY'S LAW CO
     NAME     (cm**2/s)                               (s/cm)        (dimensionless)
    -------  -----------  ----------  ----------  --------------------  ----------------------

!     SO2 =   0.1509,      1000.,        8.,          0.,          0.04 !
!     NOX =   0.1656,        1.,         8.,          5.,           3.5 !
!    HNO3 =    0.1628,       1.,        18.,          0.,     0.00000008 !

!END!


------------------------------------------------------------------------------


INPUT GROUP: 8 -- Size parameters for dry deposition of particles
--------------

   For SINGLE SPECIES, the mean and standard deviation are used to
   compute a deposition velocity for NINT (see group 9) size-ranges,
   and these are then averaged to obtain a mean deposition velocity.

   For GROUPED SPECIES, the size distribution should be explicitly
   specified (by the 'species' in the group), and the standard deviation
   for each should be entered as 0.  The model will then use the
   deposition velocity for the stated mean diameter.

    SPECIES    GEOMETRIC MASS MEAN      GEOMETRIC STANDARD
     NAME          DIAMETER                  DEVIATION
                   (microns)              (microns)
    -------    -------------------     ------------------
!     SO4 =          0.48,                  2.  !
!     NO3 =          0.48,                  2.  !
!    PM10 =          0.48,                  2.  !

!END!
```

```
--------------------------------------------------------------------------------

INPUT GROUP: 9 -- Miscellaneous dry deposition parameters
-------------

   Reference cuticle resistance (s/cm)
   (RCUTR)                    Default: 30   ! RCUTR = 30. !
   Reference ground resistance  (s/cm)
   (RGR)                      Default: 10   !   RGR = 10. !
   Reference pollutant reactivity
   (REACTR)                   Default: 8    ! REACTR = 8. !

   Number of particle-size intervals used to
   evaluate effective particle deposition velocity
   (NINT)                     Default: 9    !  NINT =  9  !

   Vegetation state in unirrigated areas
   (IVEG)                     Default: 1    !  IVEG =  1  !
     IVEG=1 for active and unstressed vegetation
     IVEG=2 for active and stressed vegetation
     IVEG=3 for inactive vegetation

!END!

--------------------------------------------------------------------------------

INPUT GROUP: 10 -- Wet Deposition Parameters
---------------

               Scavenging Coefficient -- Units: (sec)**(-1)

       Pollutant    Liquid Precip.    Frozen Precip.
       ---------    --------------    --------------
!        SO2 =        3.0E-05,          0.0E00 !
!        SO4 =        1.0E-04,          3.0E-05 !
!       HNO3 =        6.0E-05,          0.0E00 !
!        NO3 =        1.0E-04,          3.0E-05 !
!       PM10 =        1.0E-04,          3.0E-05 !

!END!

--------------------------------------------------------------------------------

INPUT GROUP: 11 -- Chemistry Parameters
---------------

   Ozone data input option (MOZ)    Default: 1        ! MOZ =  1  !
   (Used only if MCHEM = 1 or 3)
     0 = use a constant background ozone value
     1 = read hourly ozone concentrations from
         the OZONE.DAT data file
```

```
   Background ozone concentration
   (BCKO3) in ppb              Default: 80.       ! BCKO3 = 80. !
   (Used only if MCHEM = 1 or 3 and
    MOZ = 0 or (MOZ = 1 and all hourly
    O3 data missing)

   Background ammonia concentration
   (BCKNH3) in ppb              Default: 10.       ! BCKNH3 = 1. !

   Nighttime SO2 loss rate (RNITE1)
   in percent/hour              Default: 0.2       ! RNITE1 = 0.2 !

   Nighttime NOx loss rate (RNITE2)
   in percent/hour              Default: 2.0       ! RNITE2 = 2. !

   Nighttime HNO3 formation rate (RNITE3)
   in percent/hour              Default: 2.0       ! RNITE3 = 2. !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 12 -- Misc. Dispersion and Computational Parameters
---------------

   Horizontal size of puff (m) beyond which
   time-dependent dispersion equations (Heffter)
   are used to determine sigma-y and
   sigma-z (SYTDEP)                  Default: 550.   ! SYTDEP = 5.5E02 !

   Switch for using Heffter equation for sigma z
   as above (0 = Not use Heffter; 1 = use Heffter
   (MHFTSZ)                          Default: 0     ! MHFTSZ =  0   !

   Stability class used to determine plume
   growth rates for puffs above the boundary
   layer (JSUP)                      Default: 5     ! JSUP =  5   !

   Vertical dispersion constant for stable
   conditions (k1 in Eqn. 2.7-3)  (CONK1)    Default: 0.01   ! CONK1 = 0.01 !

   Vertical dispersion constant for neutral/
   unstable conditions (k2 in Eqn. 2.7-4)
   (CONK2)                           Default: 0.1    ! CONK2 = 0.1 !

   Factor for determining Transition-point from
   Schulman-Scire to Huber-Snyder Building Downwash
   scheme (SS used for Hs < Hb + TBD * HL)
   (TBD)                            Default: 0.5    ! TBD = 0.5 !
     TBD < 0   ==> always use Huber-Snyder
     TBD = 1.5 ==> always use Schulman-Scire
     TBD = 0.5 ==> ISC Transition-point

   Range of land use categories for which
   urban dispersion is assumed
   (IURB1, IURB2)                    Default: 10    ! IURB1 =  10  !
```

```
                         19    ! IURB2 =  19  !

Site characterization parameters for single-point Met data files ---------
(needed for METFM = 2,3,4)

  Land use category for modeling domain
  (ILANDUIN)                    Default: 20    ! ILANDUIN =  20  !

  Roughness length (m) for modeling domain
  (Z0IN)                      Default: 0.25   ! Z0IN = 0.25 !

  Leaf area index for modeling domain
  (XLAIIN)                     Default: 3.0    ! XLAIIN = 3. !

  Elevation above sea level (m)
  (ELEVIN)                     Default: 0.0    ! ELEVIN = 0. !

  Latitude (degrees) for met location
  (XLATIN)                     Default: -999.  ! XLATIN = -999. !

  Longitude (degrees) for met location
  (XLONIN)                     Default: -999.  ! XLONIN = -999. !

Specialized information for interpreting single-point Met data files -----

  Anemometer height (m) (Used only if METFM = 2,3)
  (ANEMHT)                      Default: 10.    ! ANEMHT = 10. !

  Form of lateral turbulance data in PROFILE.DAT file
  (Used only if METFM = 4 or MTURBVW = 1 or 3)
  (ISIGMAV)                     Default: 1      ! ISIGMAV =  2  !
     0 = read sigma-theta
     1 = read sigma-v

  Choice of mixing heights (Used only if METFM = 4)
  (IMIXCTDM)                    Default: 0      ! IMIXCTDM =  0  !
     0 = read PREDICTED mixing heights
     1 = read OBSERVED mixing heights

Maximum length of a slug (met. grid units)
(XMXLEN)                        Default: 1.0    ! XMXLEN = 1. !

Maximum travel distance of a puff/slug (in
grid units) during one sampling step
(XSAMLEN)                       Default: 1.0    ! XSAMLEN = 1. !

Maximum Number of slugs/puffs release from
one source during one time step
(MXNEW)                         Default: 99     ! MXNEW =  99  !

Maximum Number of sampling steps for
one puff/slug during one time step
(MXSAM)                         Default: 99     ! MXSAM =  99  !

Number of iterations used when computing
the transport wind for a sampling step
that includes gradual rise (for CALMET
and PROFILE winds)
```

```
(NCOUNT)                    Default: 2     ! NCOUNT =  2  !

Minimum sigma y for a new puff/slug (m)
(SYMIN)                    Default: 1.0    ! SYMIN = 1.  !

Minimum sigma z for a new puff/slug (m)
(SZMIN)                    Default: 1.0    ! SZMIN = 1.  !

Default minimum turbulence velocities
sigma-v and sigma-w for each
stability class (m/s)
(SVMIN(6) and SWMIN(6))   Default SVMIN : .50,  .50,  .50,  .50,  .50,  .50
                   Default SWMIN : .20,  .12,  .08,  .06,  .03,  .016

              Stability Class :  A    B    C    D    E    F
                                 ---  ---  ---  ---  ---  ---
                  ! SVMIN = 0.500, 0.500, 0.500, 0.500, 0.500, 0.500!
                  ! SWMIN = 0.200, 0.120, 0.080, 0.060, 0.030, 0.016!

Divergence criterion for dw/dz across puff
used to initiate adjustment for horizontal
convergence (1/s)
Partial adjustment starts at CDIV(1), and
full adjustment is reached at CDIV(2)
(CDIV(2))                 Default: 0.0,0.0  ! CDIV = 0., 0. !

Minimum wind speed (m/s) allowed for
non-calm conditions. Also used as minimum
speed returned when using power-law
extrapolation toward surface
(WSCALM)                    Default: 0.5    ! WSCALM = 0.5 !

Maximum mixing height (m)
(XMAXZI)                   Default: 3000.  ! XMAXZI = 3000. !

Minimum mixing height (m)
(XMINZI)                   Default: 50.    ! XMINZI = 50. !

Default wind speed classes --
5 upper bounds (m/s) are entered;
the 6th class has no upper limit
(WSCAT(5))              Default   :
                  ISC RURAL : 1.54, 3.09, 5.14, 8.23, 10,8 (10.8+)

              Wind Speed Class :  1    2    3    4    5    6
                                 ---  ---  ---  ---  ---  ---
                  ! WSCAT = 1.54, 3.09, 5.14, 8.23, 10.80 !

Default wind speed profile power-law
exponents for stabilities 1-6
(PLX0(6))              Default   : ISC RURAL values
                  ISC RURAL : .07, .07, .10, .15, .35, .55
                  ISC URBAN : .15, .15, .20, .25, .30, .30

              Stability Class :  A    B    C    D    E    F
                                 ---  ---  ---  ---  ---  ---
                  ! PLX0 = 0.07, 0.07, 0.10, 0.15, 0.35, 0.55 !
```

```
Default potential temperature gradient
for stable classes E, F (degK/m)
(PTG0(2))              Default: 0.020, 0.035
                     ! PTG0 = 0.020,  0.035 !

Default plume path coefficients for
each stability class (used when option
for partial plume height terrain adjustment
is selected -- MCTADJ=3)
(PPC(6))           Stability Class :  A    B    C    D    E    F
                  Default  PPC : .50, .50, .50, .50, .35, .35
                                 ---  ---  ---  ---  ---  ---
                     !  PPC = 0.50, 0.50, 0.50, 0.50, 0.35, 0.35 !

Slug-to-puff transition criterion factor
equal to sigma-y/length of slug
(SL2PF)                 Default: 10.      ! SL2PF = 10. !

Puff-splitting control variables ------------------------

  Number of puffs that result every time a puff
  is split - nsplit=2 means that 1 puff splits
  into 2
  (NSPLIT)              Default:  3      ! NSPLIT =  3  !

  Time(s) of a day when split puffs are eligible to
  be split once again; this is typically set once
  per day, around sunset before nocturnal shear develops.
  24 values: 0 is midnight (00:00) and 23 is 11 PM (23:00)
  0=do not re-split    1=eligible for re-split
  (IRESPLIT(24))          Default:  Hour 17 = 1
  !  IRESPLIT = 0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0,0,0,0 !

  Split is allowed only if last hour's mixing
  height (m) exceeds a minimum value
  (ZISPLIT)             Default: 100.     ! ZISPLIT = 100. !

  Split is allowed only if ratio of last hour's
  mixing ht to the maximum mixing ht experienced
  by the puff is less than a maximum value (this
  postpones a split until a nocturnal layer develops)
  (ROLDMAX)               Default: 0.25      ! ROLDMAX = 0.25 !

Integration control variables ------------------------

  Fractional convergence criterion for numerical SLUG
  sampling integration
  (EPSSLUG)              Default:   1.0e-04  ! EPSSLUG = 1.0E-04 !

  Fractional convergence criterion for numerical AREA
  source integration
  (EPSAREA)              Default:   1.0e-06  ! EPSAREA = 1.0E-06 !

  Trajectory step-length (m) used for numerical rise
  integration
  (DSRISE)               Default:   1.0     ! DSRISE = 1. !

!END!
```

```
---------------------------------------------------------------------------

INPUT GROUPS: 13a, 13b, 13c, 13d -- Point source parameters
--------------------------------

---------------
Subgroup (13a)
---------------

     Number of point sources with
     parameters provided below      (NPT1)  No default  !  NPT1 = 2  !

     Units used for point source
     emissions below               (IPTU)  Default: 1  !  IPTU =   1  !
          1 =      g/s
          2 =      kg/hr
          3 =      lb/hr
          4 =    tons/yr
          5 =    Odour Unit * m**3/s  (vol. flux of odour compound)
          6 =    Odour Unit * m**3/min
          7 =    metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (13d)       (NSPT1) Default: 0  !  NSPT1 =  0  !

     Number of point sources with
     variable emission parameters
     provided in external file     (NPT2)  No default  !  NPT2 =  0  !

     (If NPT2 > 0, these point
     source emissions are read from
     the file: PTEMARB.DAT)

!END!

---------------
Subgroup (13b)
---------------
                              a
        POINT SOURCE: CONSTANT DATA
        -----------------------------
                                                     b         c

 Source     X UTM     Y UTM     Stack  Base     Stack   Exit  Exit   Bldg.  Emission
  No.    Coordinate Coordinate Height Elevation Diameter  Vel.  Temp.  Dwash   Rates
          (km)       (km)       (m)     (m)      (m)   (m/s) (deg. K)
 ------  ---------- ---------- ------  ------  -------- ----- -------- ----- --------
4 CT UNITS, COMBINED CYCLE MODE- FUEL OIL
WORSE CASE EMISSIONS ARE FOR BASE LOAD, 35 DEG F

Subgroup (13b)
 1  ! SRCNAM = BASE35   !
```

```
1 ! X =  543.10, 2992.90, 36.6, 0.00, 5.79, 22.43, 420.4, 1.0, 51.96, 3.26, 48.08, 0.0, 0.0, 19.05, 34.32 ! !
2 ! SRCNAM = COOLTOW !
2 ! X =  543.10, 2992.90, 13.7, 0.00,11.58, 6.21, 313.2, 1.0, 0.0, 0.0, 0.0, 0.0, 0.0, 0.586, 0.0 ! !END!
```

....

a
Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.

b
0. = No building downwash modeled, 1. = downwash modeled
NOTE: must be entered as a REAL number (i.e., with decimal point)

c
An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by IPTU
(e.g. 1 for g/s).

....
Subgroup (13c)
....
BUILDING DIMENSION DATA FOR SOURCES SUBJECT TO DOWNWASH
....

```
Subgroup (13c)
   1 ! SRCNAM = BASE35  !
   1 ! HEIGHT = 25.30, 25.30, 25.30, 25.30, 25.30, 25.30,
         25.30, 25.30, 25.30, 25.30, 25.30, 25.30,
         25.30, 25.30, 25.30, 25.30, 25.30, 25.30,
         25.30, 25.30, 25.30, 25.30, 25.30, 25.30,
         25.30, 25.30, 25.30, 25.30, 25.30, 25.30,
         25.30, 25.30, 25.30, 25.30, 25.30, 25.30 !
   1 ! WIDTH =  13.25, 16.64, 19.53, 21.83, 23.46, 24.38,
         24.56, 24.00, 22.70, 24.00, 24.57, 24.39,
         23.47, 21.83, 19.53, 16.64, 13.25,  9.45,
         13.25, 16.64, 19.53, 21.83, 23.46, 24.38,
         24.56, 24.00, 22.70, 24.00, 24.57, 24.39,
         23.47, 21.83, 19.53, 16.64, 13.25,  9.45 !

!END!
   2 ! SRCNAM = COOLTOW !
   2 ! HEIGHT = 12.19, 12.19, 12.19, 12.19, 12.19, 12.19,
         12.19, 12.19, 12.19, 12.19, 12.19, 12.19,
         12.19, 12.19, 12.19, 12.19, 12.19, 12.19,
         12.19, 12.19, 12.19, 12.19, 12.19, 12.19,
         12.19, 12.19, 12.19, 12.19, 12.19, 12.19,
         12.19, 12.19, 12.19, 12.19, 12.19, 12.19 !
   2 ! WIDTH = 151.52, 150.38, 144.66, 134.56, 120.36, 102.50,
         81.54, 58.09, 32.88, 58.09, 81.54, 102.50,
        120.36, 134.56, 144.66, 150.38, 151.52, 148.06,
        151.52, 150.38, 144.66, 134.56, 120.36, 102.50,
         81.54, 58.09, 32.88, 58.09, 81.54, 102.50,
        120.36, 134.56, 144.66, 150.38, 151.52, 148.06 !

!END!
```

Source a
No. Effective building width and height (in meters) every 10 degrees
------ --

----

a
Each pair of width and height values is treated as a separate input subgroup and therefore must end with an input group terminator.

Subgroup (13d)
----

a
POINT SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission rates given in 13b. Factors entered multiply the rates in 13b. Skip sources here that have constant emissions. For more elaborate variation in source parameters, use PTEMARB.DAT and NPT2 > 0.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0
0 = Constant
1 = Diurnal cycle (24 scaling factors: hours 1-24)
2 = Monthly cycle (12 scaling factors: months 1-12)
3 = Hour & Season (4 groups of 24 hourly scaling factors, where first group is DEC-JAN-FEB)
4 = Speed & Stab. (6 groups of 6 scaling factors, where first group is Stability Class A, and the speed classes have upper bounds (m/s) defined in Group 12
5 = Temperature (12 scaling factors, where temperature classes have upper bounds (C) of: 0, 5, 10, 15, 20, 25, 30, 35, 40, 45, 50, 50+)

----
a
Data for each species are treated as a separate input subgroup and therefore must end with an input group terminator.

INPUT GROUPS: 14a, 14b, 14c, 14d -- Area source parameters

Subgroup (14a)

Number of polygon area sources with

```
   parameters specified below (NAR1)      No default  !  NAR1 =  0   !

   Units used for area source
   emissions below          (IARU)     Default: 1  !  IARU =   1  !
       1 =      g/m**2/s
       2 =     kg/m**2/hr
       3 =     lb/m**2/hr
       4 =    tons/m**2/yr
       5 =    Odour Unit * m/s  (vol. flux/m**2 of odour compound)
       6 =    Odour Unit * m/min
       7 =    metric tons/m**2/yr

   Number of source-species
   combinations with variable
   emissions scaling factors
   provided below in (14d)       (NSAR1) Default: 0  !  NSAR1 =  0  !

   Number of buoyant polygon area sources
   with variable location and emission
   parameters (NAR2)                   No default  !  NAR2 =  0   !
   (If NAR2 > 0, ALL parameter data for
   these sources are read from the file: BAEMARB.DAT)

!END!

---------------
Subgroup (14b)
---------------
                            a
      AREA SOURCE: CONSTANT DATA
      --------------------------
                                             b
Source        Effect.   Base     Initial   Emission
 No.          Height  Elevation  Sigma z     Rates
               (m)      (m)       (m)
------        ------   ------   --------  --------


--------
   a
    Data for each source are treated as a separate input subgroup
    and therefore must end with an input group terminator.
   b
    An emission rate must be entered for every pollutant modeled.
    Enter emission rate of zero for secondary pollutants that are
    modeled, but not emitted.  Units are specified by IARU
    (e.g. 1 for g/m**2/s).

---------------
Subgroup (14c)
---------------

      COORDINATES (UTM-km) FOR EACH VERTEX(4) OF EACH POLYGON
      --------------------------------------------------------
Source                                                    a
 No.      Ordered list of X followed by list of Y, grouped by source
------    ------------------------------------------------------------
```

----
 a
 Data for each source are treated as a separate input subgroup
 and therefore must end with an input group terminator.

Subgroup (14d)
----

 a
 AREA SOURCE: VARIABLE EMISSIONS DATA

 Use this subgroup to describe temporal variations in the emission
 rates given in 14b. Factors entered multiply the rates in 14b.
 Skip sources here that have constant emissions. For more elaborate
 variation in source parameters, use BAEMARB.DAT and NAR2 > 0.

 IVARY determines the type of variation, and is source-specific:
 (IVARY) Default: 0
 0 = Constant
 1 = Diurnal cycle (24 scaling factors: hours 1-24)
 2 = Monthly cycle (12 scaling factors: months 1-12)
 3 = Hour & Season (4 groups of 24 hourly scaling factors,
 where first group is DEC-JAN-FEB)
 4 = Speed & Stab. (6 groups of 6 scaling factors, where
 first group is Stability Class A,
 and the speed classes have upper
 bounds (m/s) defined in Group 12
 5 = Temperature (12 scaling factors, where temperature
 classes have upper bounds (C) of:
 0, 5, 10, 15, 20, 25, 30, 35, 40,
 45, 50, 50+)

----
 a
 Data for each species are treated as a separate input subgroup
 and therefore must end with an input group terminator.

INPUT GROUPS: 15a, 15b, 15c -- Line source parameters

Subgroup (15a)

 Number of buoyant line sources
 with variable location and emission
 parameters (NLN2) No default ! NLN2 = 0 !

 (If NLN2 > 0, ALL parameter data for
 these sources are read from the file: LNEMARB.DAT)

Number of buoyant line sources (NLINES) No default ! NLINES = 0 !

Units used for line source
emissions below (ILNU) Default: 1 ! ILNU = 1 !
1 = g/s
2 = kg/hr
3 = lb/hr
4 = tons/yr
5 = Odour Unit * m**3/s (vol. flux of odour compound)
6 = Odour Unit * m**3/min
7 = metric tons/yr

Number of source-species
combinations with variable
emissions scaling factors
provided below in (15c) (NSLN1) Default: 0 ! NSLN1 = 0 !

Maximum number of segments used to model
each line (MXNSEG) Default: 7 ! MXNSEG = 7 !

The following variables are required only if NLINES > 0. They are
used in the buoyant line source plume rise calculations.

Number of distances at which Default: 6 ! NLRISE = 6 !
transitional rise is computed

Average building length (XL) No default ! XL = 0. !
(in meters)

Average building height (HBL) No default ! HBL = 0. !
(in meters)

Average building width (WBL) No default ! WBL = 0. !
(in meters)

Average line source width (WML) No default ! WML = 0. !
(in meters)

Average separation between buildings (DXL) No default ! DXL = 0. !
(in meters)

Average buoyancy parameter (FPRIMEL) No default ! FPRIMEL = 0. !
(in m**4/s**3)

!END!

....
Subgroup (15b)
....

BUOYANT LINE SOURCE: CONSTANT DATA
....

Source No.	Beg. X Coordinate (km)	Beg. Y Coordinate (km)	End. X Coordinate (km)	End. Y Coordinate (km)	Release Height (m)	Base Elevation (m)	Emission Rates
......	....	....	....	....	......	....	....

a

....

a
Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.

b
An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by ILNTU
(e.g. 1 for g/s).

....
Subgroup (15c)
....

a
BUOYANT LINE SOURCE: VARIABLE EMISSIONS DATA
....

Use this subgroup to describe temporal variations in the emission
rates given in 15b. Factors entered multiply the rates in 15b.
Skip sources here that have constant emissions.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0
0 = Constant
1 = Diurnal cycle (24 scaling factors: hours 1-24)
2 = Monthly cycle (12 scaling factors: months 1-12)
3 = Hour & Season (4 groups of 24 hourly scaling factors, where first group is DEC-JAN-FEB)
4 = Speed & Stab. (6 groups of 6 scaling factors, where first group is Stability Class A, and the speed classes have upper bounds (m/s) defined in Group 12
5 = Temperature (12 scaling factors, where temperature classes have upper bounds (C) of: 0, 5, 10, 15, 20, 25, 30, 35, 40, 45, 50, 50+)

....
a
Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

....

INPUT GROUPS: 16a, 16b, 16c -- Volume source parameters
....

....
Subgroup (16a)
....

Number of volume sources with
parameters provided in 16b,c (NVL1) No default ! NVL1 = 0 !

Units used for volume source
emissions below in 16b (IVLU) Default: 1 ! IVLU = 1 !
1 = g/s
2 = kg/hr
3 = lb/hr
4 = tons/yr
5 = Odour Unit * m**3/s (vol. flux of odour compound)
6 = Odour Unit * m**3/min
7 = metric tons/yr

Number of source-species
combinations with variable
emissions scaling factors
provided below in (16c) (NSVL1) Default: 0 ! NSVL1 = 0 !

Gridded volume source data
used ? (IGRDVL) No default ! IGRDVL = 0 !
0 = no
1 = yes (gridded volume source
emissions read from the file:
VOLEM.DAT)

The following parameters apply to the data in the
gridded volume source emissions file (VOLEM.DAT)

- Effective height of emissions
(VEFFHT) in meters No default ! VEFFHT = 0. !

- Initial sigma y (VSIGYI) in
meters No default ! VSIGYI = 0. !

- Initial sigma z (VSIGZI) in
meters No default ! VSIGZI = 0. !

!END!

....
Subgroup (16b)
....

a
VOLUME SOURCE: CONSTANT DATA
....

b

X UTM Coordinate (km)	Y UTM Coordinate (km)	Effect. Height (m)	Base Elevation (m)	Initial Sigma y (m)	Initial Sigma z (m)	Emission Rates

....
a
Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.

b

An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by IVLU
(e.g. 1 for g/s).

....
Subgroup (16c)
....

a
VOLUME SOURCE: VARIABLE EMISSIONS DATA
....

Use this subgroup to describe temporal variations in the emission
rates given in 16b. Factors entered multiply the rates in 16b.
Skip sources here that have constant emissions. For more elaborate
variation in source parameters, use VOLEM.DAT and IGRDVL = 1.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0
0 = Constant
1 = Diurnal cycle (24 scaling factors: hours 1-24)
2 = Monthly cycle (12 scaling factors: months 1-12)
3 = Hour & Season (4 groups of 24 hourly scaling factors,
where first group is DEC-JAN-FEB)
4 = Speed & Stab. (6 groups of 6 scaling factors, where
first group is Stability Class A,
and the speed classes have upper
bounds (m/s) defined in Group 12
5 = Temperature (12 scaling factors, where temperature
classes have upper bounds (C) of:
0, 5, 10, 15, 20, 25, 30, 35, 40,
45, 50, 50+)

....
a
Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

....

INPUT GROUPS: 17a & 17b -- Non-gridded (discrete) receptor information
....

....
Subgroup (17a)
....

Number of non-gridded receptors (NREC) No default ! NREC = 126 !

!END!

....
Subgroup (17b)
....

a

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        NON-GRIDDED (DISCRETE) RECEPTOR DATA
        ------------------------------------

              X UTM      Y UTM       Ground       Height  b
Receptor    Coordinate  Coordinate  Elevation   Above Ground
 No.          (km)        (km)         (m)          (m)
-------     --------   --------    --------    ----------
   1 ! X =    557.0,    2789.0,      0.000,      0.000!  !END!
   2 ! X =    556.6,    2792.0,      0.000,      0.000!  !END!
   3 ! X =    556.0,    2796.0,      0.000,      0.000!  !END!
   4 ! X =    553.0,    2796.5,      0.000,      0.000!  !END!
   5 ! X =    548.0,    2796.5,      0.000,      0.000!  !END!
   6 ! X =    542.7,    2796.5,      0.000,      0.000!  !END!
   7 ! X =    542.7,    2800.0,      0.000,      0.000!  !END!
   8 ! X =    542.7,    2805.0,      0.000,      0.000!  !END!
   9 ! X =    542.7,    2810.0,      0.000,      0.000!  !END!
  10 ! X =    542.0,    2811.0,      0.000,      0.000!  !END!
  11 ! X =    541.3,    2814.0,      0.000,      0.000!  !END!
  12 ! X =    542.7,    2816.0,      0.000,      0.000!  !END!
  13 ! X =    544.1,    2820.0,      0.000,      0.000!  !END!
  14 ! X =    543.5,    2824.6,      0.000,      0.000!  !END!
  15 ! X =    545.0,    2829.0,      0.000,      0.000!  !END!
  16 ! X =    545.7,    2832.2,      0.000,      0.000!  !END!
  17 ! X =    546.2,    2835.7,      0.000,      0.000!  !END!
  18 ! X =    548.6,    2837.5,      0.000,      0.000!  !END!
  19 ! X =    550.3,    2839.0,      0.000,      0.000!  !END!
  20 ! X =    545.0,    2839.0,      0.000,      0.000!  !END!
  21 ! X =    540.0,    2839.0,      0.000,      0.000!  !END!
  22 ! X =    550.5,    2844.0,      0.000,      0.000!  !END!
  23 ! X =    545.0,    2844.0,      0.000,      0.000!  !END!
  24 ! X =    540.0,    2844.0,      0.000,      0.000!  !END!
  25 ! X =    550.3,    2848.6,      0.000,      0.000!  !END!
  26 ! X =    549.0,    2848.6,      0.000,      0.000!  !END!
  27 ! X =    548.0,    2848.6,      0.000,      0.000!  !END!
  28 ! X =    547.0,    2848.6,      0.000,      0.000!  !END!
  29 ! X =    546.0,    2848.6,      0.000,      0.000!  !END!
  30 ! X =    545.0,    2848.6,      0.000,      0.000!  !END!
  31 ! X =    544.0,    2848.6,      0.000,      0.000!  !END!
  32 ! X =    543.0,    2848.6,      0.000,      0.000!  !END!
  33 ! X =    542.0,    2848.6,      0.000,      0.000!  !END!
  34 ! X =    541.0,    2848.6,      0.000,      0.000!  !END!
  35 ! X =    540.0,    2848.6,      0.000,      0.000!  !END!
  36 ! X =    539.0,    2848.6,      0.000,      0.000!  !END!
  37 ! X =    538.0,    2848.6,      0.000,      0.000!  !END!
  38 ! X =    537.0,    2848.6,      0.000,      0.000!  !END!
  39 ! X =    536.0,    2848.6,      0.000,      0.000!  !END!
  40 ! X =    535.0,    2848.6,      0.000,      0.000!  !END!
  41 ! X =    534.0,    2848.6,      0.000,      0.000!  !END!
  42 ! X =    533.0,    2848.6,      0.000,      0.000!  !END!
  43 ! X =    532.0,    2848.6,      0.000,      0.000!  !END!
  44 ! X =    531.0,    2848.6,      0.000,      0.000!  !END!
  45 ! X =    530.0,    2848.6,      0.000,      0.000!  !END!
  46 ! X =    529.0,    2848.6,      0.000,      0.000!  !END!
  47 ! X =    528.0,    2848.6,      0.000,      0.000!  !END!
  48 ! X =    527.0,    2848.6,      0.000,      0.000!  !END!
  49 ! X =    526.0,    2848.6,      0.000,      0.000!  !END!
  50 ! X =    525.0,    2848.6,      0.000,      0.000!  !END!
  51 ! X =    524.0,    2848.6,      0.000,      0.000!  !END!
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 52 ! X =    523.0,   2848.6,    0.000,    0.000!  !END!
 53 ! X =    522.0,   2848.6,    0.000,    0.000!  !END!
 54 ! X =    521.0,   2848.6,    0.000,    0.000!  !END!
 55 ! X =    520.0,   2848.6,    0.000,    0.000!  !END!
 56 ! X =    519.0,   2848.6,    0.000,    0.000!  !END!
 57 ! X =    518.0,   2848.6,    0.000,    0.000!  !END!
 58 ! X =    517.0,   2848.6,    0.000,    0.000!  !END!
 59 ! X =    516.0,   2848.6,    0.000,    0.000!  !END!
 60 ! X =    515.0,   2848.6,    0.000,    0.000!  !END!
 61 ! X =    514.5,   2848.6,    0.000,    0.000!  !END!
 62 ! X =    514.5,   2848.0,    0.000,    0.000!  !END!
 63 ! X =    514.5,   2847.6,    0.000,    0.000!  !END!
 64 ! X =    514.5,   2846.6,    0.000,    0.000!  !END!
 65 ! X =    514.5,   2845.0,    0.000,    0.000!  !END!
 66 ! X =    514.5,   2844.0,    0.000,    0.000!  !END!
 67 ! X =    514.5,   2843.0,    0.000,    0.000!  !END!
 68 ! X =    514.5,   2842.0,    0.000,    0.000!  !END!
 69 ! X =    514.5,   2841.0,    0.000,    0.000!  !END!
 70 ! X =    514.5,   2840.0,    0.000,    0.000!  !END!
 71 ! X =    514.5,   2839.0,    0.000,    0.000!  !END!
 72 ! X =    514.5,   2838.0,    0.000,    0.000!  !END!
 73 ! X =    514.5,   2837.0,    0.000,    0.000!  !END!
 74 ! X =    514.5,   2836.0,    0.000,    0.000!  !END!
 75 ! X =    514.5,   2835.0,    0.000,    0.000!  !END!
 76 ! X =    514.5,   2834.0,    0.000,    0.000!  !END!
 77 ! X =    514.5,   2833.0,    0.000,    0.000!  !END!
 78 ! X =    514.5,   2832.5,    0.000,    0.000!  !END!
 79 ! X =    510.0,   2832.5,    0.000,    0.000!  !END!
 80 ! X =    509.0,   2832.5,    0.000,    0.000!  !END!
 81 ! X =    508.0,   2832.5,    0.000,    0.000!  !END!
 82 ! X =    507.0,   2832.5,    0.000,    0.000!  !END!
 83 ! X =    506.0,   2832.5,    0.000,    0.000!  !END!
 84 ! X =    505.0,   2832.5,    0.000,    0.000!  !END!
 85 ! X =    504.0,   2832.5,    0.000,    0.000!  !END!
 86 ! X =    503.0,   2832.5,    0.000,    0.000!  !END!
 87 ! X =    502.0,   2832.5,    0.000,    0.000!  !END!
 88 ! X =    501.0,   2832.5,    0.000,    0.000!  !END!
 89 ! X =    500.0,   2832.5,    0.000,    0.000!  !END!
 90 ! X =    499.0,   2832.5,    0.000,    0.000!  !END!
 91 ! X =    498.0,   2832.5,    0.000,    0.000!  !END!
 92 ! X =    497.0,   2832.5,    0.000,    0.000!  !END!
 93 ! X =    496.0,   2832.5,    0.000,    0.000!  !END!
 94 ! X =    495.0,   2832.5,    0.000,    0.000!  !END!
 95 ! X =    495.0,   2833.0,    0.000,    0.000!  !END!
 96 ! X =    495.0,   2834.0,    0.000,    0.000!  !END!
 97 ! X =    495.0,   2835.0,    0.000,    0.000!  !END!
 98 ! X =    495.0,   2836.0,    0.000,    0.000!  !END!
 99 ! X =    494.5,   2837.0,    0.000,    0.000!  !END!
100 ! X =    491.5,   2841.0,    0.000,    0.000!  !END!
101 ! X =    488.5,   2845.5,    0.000,    0.000!  !END!
102 ! X =    483.0,   2848.5,    0.000,    0.000!  !END!
103 ! X =    480.0,   2852.5,    0.000,    0.000!  !END!
104 ! X =    475.0,   2854.0,    0.000,    0.000!  !END!
105 ! X =    473.5,   2857.0,    0.000,    0.000!  !END!
106 ! X =    473.0,   2860.0,    0.000,    0.000!  !END!
107 ! X =    472.0,   2860.0,    0.000,    0.000!  !END!
108 ! X =    471.0,   2860.0,    0.000,    0.000!  !END!
109 ! X =    470.0,   2860.0,    0.000,    0.000!  !END!
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110 ! X =    469.0,   2860.0,   0.000,    0.000!  !END!
111 ! X =    468.0,   2860.0,   0.000,    0.000!  !END!
112 ! X =    467.0,   2860.0,   0.000,    0.000!  !END!
113 ! X =    466.0,   2860.0,   0.000,    0.000!  !END!
114 ! X =    465.0,   2860.0,   0.000,    0.000!  !END!
115 ! X =    464.0,   2860.0,   0.000,    0.000!  !END!
116 ! X =    463.0,   2860.0,   0.000,    0.000!  !END!
117 ! X =    462.0,   2860.0,   0.000,    0.000!  !END!
118 ! X =    461.0,   2860.0,   0.000,    0.000!  !END!
119 ! X =    460.0,   2860.0,   0.000,    0.000!  !END!
120 ! X =    459.5,   2863.2,   0.000,    0.000!  !END!
121 ! X =    459.0,   2863.2,   0.000,    0.000!  !END!
122 ! X =    458.0,   2863.2,   0.000,    0.000!  !END!
123 ! X =    457.0,   2863.2,   0.000,    0.000!  !END!
124 ! X =    456.0,   2863.2,   0.000,    0.000!  !END!
125 ! X =    455.0,   2863.2,   0.000,    0.000!  !END!
126 ! X =    454.0,   2863.2,   0.000,    0.000!  !END!
```

....

a
Data for each receptor are treated as a separate input subgroup and therefore must end with an input group terminator.

b
Receptor height above ground is optional. If no value is entered, the receptor is placed on the ground.