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BUREAU OF AIR REGULATION

AIR PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS FOR THE IPS AVON PARK CORPORATION, DESOTO COUNTY, FLORIDA

Prepared For:

IPS Avon Park Corporation
1560 Gulf Blvd., #701
Clearwater, Florida 32767

Prepared By:

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

February 2000
9939557Y/F1/WP

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PART A

AIR PERMIT APPLICATION

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: **IPS Avon Park Corporation**	
2. Site Name: **IPS DeSoto Power Project**	
3. Facility Identification Number: [X] Unknown	
4. Facility Location: Street Address or Other Locator: **2 Miles East of Arcadia** City: **Unincorporated** County: **DeSoto** Zip Code:	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [ ] Yes [X] No

Application Contact

1. Name and Title of Application Contact: **Mr. John S. Ellis, President**
2. Application Contact Mailing Address: Organization/Firm: **IPS Avon Corporation** Street Address: **1560 Gulf Blvd., #701** City: **Clearwater** State: **FL** Zip Code: **32767**
3. Application Contact Telephone Numbers: Telephone: (**727**) **517 - 7140** Fax: (**727**) **517 - 1255**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	February 9, 2000
2. Permit Number:	0270016-001-AC
3. PSD Number (if applicable):	PSD-FL-284
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 S. Ellis, President
2. Owner/Authorized Representative or Responsible Official Mailing Address:
   Organization/Firm: **IPS Avon Park Corporation**
   Street Address: **1560 Gulf Blvd., #701**
   City: **Clearwater** State: **FL** Zip Code: **33767**
3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
   Telephone: (**727**) **517 - 7140** Fax: (**727**) **517 - 1255**
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.*

   John S. Ellis, Pres. 1-25-2000
   Signature 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 2/4/2000

Signature Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
--	GE Frame 7FA Combustion Turbine	AC1A	
--	GE Frame 7FA Combustion Turbine	AC1A	
--	GE Frame 7FA Combustion Turbine	AC1A	
--	Unregulated Emissions	AC1A	

Application Processing Fee

Check one: [X] Attached - Amount: $: 7,500 [ ] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Construction of 3 170-MW GE Frame 7FA combustion turbines. See Attachment PSD-IPS.**	
2. Projected or Actual Date of Commencement of Construction:	**1 Jul 2000**
3. Projected Date of Completion of Construction:	**1 Jan 2002**

Application Comment

See Attachment PSD-IPS

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17** East (km): **419.75** North (km): **3011.5**			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **27 / 13 / 30** Longitude (DD/MM/SS): **81 / 48 / 42**			
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters): **Project consists of three 170-MW dual-fuel, General Electric Frame 7FA combustion turbines that will use dry low-nitrogen oxide combustion technology when firing natural gas and water injection when firing distillate fuel oil. Each CT will operate up to 3,390 hours per year.**			

Facility Contact

1. Name and Title of Facility Contact: **Mr. John S. Ellis, President**
2. Facility Contact Mailing Address: Organization/Firm: **IPS Avon Park Corporation** Street Address: **1560 Gulf Blvd., #701** City: **Clearwater** State: **FL** Zip Code: **33767**
3. Facility Contact Telephone Numbers: Telephone: (**727**) **517 - 7140** Fax: (**727**) **517 - 1255**

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. [ ] 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 is subject to NSPS Subpart GG. The tanks are subject to Subpart Kb.**	

List of Applicable Regulations

Not Applicable	

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	**B**				**Particulate Matter-Total**
VOC	**B**				**Volatile Organic Compounds**
SO_2	**A**				**Sulfur Dioxide**
NO_x	**A**				**Nitrogen Oxides**
CO	**A**				**Carbon Monoxides**
PM_{10}	**B**				**Particulate Matter-PM_{10}**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1.	Area Map Showing Facility Location: [X] Attached, Document ID: PSD-IPS [ ] Not Applicable [ ] Waiver Requested
2.	Facility Plot Plan: [X] Attached, Document ID: PSD-IPS [ ] Not Applicable [ ] Waiver Requested
3.	Process Flow Diagram(s): [X] Attached, Document ID: PSD-IPS [ ] 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-IPS [ ] 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 Combustion Turbine

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 combustion turbine operating in simple cycle mode. See Attachment PSD-IPS.

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

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Water injection - distillate oil firing**
2. Control Device or Method Code(s): **28**

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:		**1,612**	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 at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,806 MMBtu/hr (ISO-LHV) and 182 MW.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment IPS-EU1-D for operational requirements	
See Attachment PSD-IPS for permitting requirements	

ATTACHMENT IPS-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/H2SO4/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-Accessability 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
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40 CFR 75.54(c)	Recordkeeping-SO_2
40 CFR 75.54(d)	Recordkeeping- NO_x
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40 CFR 75.55(c)	General Recordkeeping (Specific Situations)
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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)

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 Att. PSD-IPS**	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: **60** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,646,000**	10. Water Vapor: **8.6** %

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

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **419.75** North (km): **3011.5**

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

Stack parameters for ISO operating condition firing natural gas; for oil 1,094°F and 2,731,000 ACFM.

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: **13.9**	5. Maximum Annual Rate: **13,900**	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, 1,000 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: **1.70**	5. Maximum Annual Rate: **5,752**	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 3,390 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	026	028	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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** 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): **Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - all loads; 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **101.5** lb/hour **49.3** 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 @ 32°F; 100% load;TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **8.4** 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. Gas firing, 1 gram/100 cf - 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **42 ppmvd**	4. Equivalent Allowable Emissions: **362.0** lb/hour **175.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling 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 @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **9 ppmvd**	4. Equivalent Allowable Emissions: **66.7** lb/hour **108.6** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling 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; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **20 ppmvd**	4. Equivalent Allowable Emissions: **74.4** lb/hour **35.7** 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): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.2** lb/hour **72.0** 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; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **7 ppmvw**	4. Equivalent Allowable Emissions: **16.7** lb/hour **8.1** 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 @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **1.4 ppmvd**	4. Equivalent Allowable Emissions: **3** lb/hour **4.8** 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; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: 17 lb/hour 20.5 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: GE, 1998; Golder	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See Attachment PSD-IPS; Section 2.0; Appendix A.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: 17 lb/hr	4. Equivalent Allowable Emissions: 17 lb/hour 8.5 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): Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17.0** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **20** % 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 oil firing.**	

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: **01 Jan 2002**	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.**	

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): **FDEP 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: **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-IPS [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD-IPS [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD-IPS [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD-IPS [ ] 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-IPS [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD-IPS [ ] 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 Combustion Turbine

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 combustion turbine operating in simple cycle mode. See Attachment PSD-IPS.

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

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Water injection - distillate oil firing**	
2. Control Device or Method Code(s): **28**	

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:			**1,612**	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 at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,806 MMBtu/hr (ISO-LHV) and 182 MW.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment IPS-EU1-D for operational requirements	
See Attachment PSD-IPS 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 Att. PSD-IPS**	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: **60** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,646,000** acfm	10. Water Vapor: **8.6** %

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

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **419.75** North (km): **3011.5**

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

Stack parameters for ISO operating condition firing natural gas; for oil 1,094°F and 2,731,000 ACFM.

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: **13.9**	5. Maximum Annual Rate: **13,900**	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, 1,000 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: **1.70**	5. Maximum Annual Rate: **5,752**	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 3,390 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	026	028	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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** 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): **Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - all loads; 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **101.5** lb/hour **49.3** 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 @ 32°F; 100% load;TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **8.4** 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. Gas firing, 1 gram/100 cf - 32°F, 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **42 ppmvd**	4. Equivalent Allowable Emissions: **362.0** lb/hour **175.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling 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 @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **9 ppmvd**	4. Equivalent Allowable Emissions: **66.7** lb/hour **108.6** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling 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; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **74.4** lb/hour **86.5** tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **GE, 1998; Golder**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   See Attachment PSD-IPS; Section 2.0; Appendix A.
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **20 ppmvd**
4. Equivalent Allowable Emissions: **74.4** lb/hour **35.7** 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):

   Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.2** lb/hour **72.0** 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; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **7 ppmvw**	4. Equivalent Allowable Emissions: **16.7** lb/hour **8.1** 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 @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **1.4 ppmvd**	4. Equivalent Allowable Emissions: **3** lb/hour **4.8** 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; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** 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): **Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17.0** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **20** % 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 oil firing.**	

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: **01 Jan 2002**	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.**	

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): **FDEP 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: **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-IPS [ ] Not Applicable [ ] Waiver Requested	
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD-IPS [ ] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD-IPS [ ] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD-IPS [ ] 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-IPS [ ] Not Applicable	
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD-IPS [ ] 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 Combustion Turbine

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 combustion turbine operating in simple cycle mode. See Attachment PSD-IPS.

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

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Water injection - distillate oil firing**	
2. Control Device or Method Code(s): **28**	

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:		**1,612** 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 at ISO conditions and natural gas firing (LHV); maximum for oil firing is 1,806 MMBtu/hr (ISO-LHV) and 182 MW.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment IPS-EU1-D for operational requirements	
See Attachment PSD-IPS 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 Att. PSD-IPS**	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: **60** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,646,000** acfm	10. Water Vapor: **8.6** %

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

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **419.75** North (km): **3011.50**

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

Stack parameters for ISO operating condition firing natural gas; for oil 1,094°F and 2,731,000 ACFM.

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: **13.9**	5. Maximum Annual Rate: **13,900**	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, 1,000 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: **1.70**	5. Maximum Annual Rate: **5,752**	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 3,390 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	026	028	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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** 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): **Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; all loads. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - all loads; 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **101.5** lb/hour **49.3** 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 @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **101.5** lb/hour **55.3** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **See Comment**	4. Equivalent Allowable Emissions: **5.1** lb/hour **8.4** 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. Gas firing, 1 gram/100 cf - 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **42 ppmvd**	4. Equivalent Allowable Emissions: **362.0** lb/hour **175.4** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling 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 @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **362** lb/hour **252** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **9 ppmvd**	4. Equivalent Allowable Emissions: **66.7** lb/hour **108.6** tons/year
5. Method of Compliance (limit to 60 characters): **CEM - 30 Day Rolling 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; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **20 ppmvd**	4. Equivalent Allowable Emissions: **74.4** lb/hour **35.7** 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): **Oil firing; max @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **74.4** lb/hour **86.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.2** lb/hour **72.0** 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; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **16.7** lb/hour **11.5** tons/year

4. Synthetically Limited? [X]

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

6. Emission Factor:
Reference: **GE, 1998; Golder**

7. Emissions Method Code: **2**

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

See Attachment PSD-IPS; Section 2.0; Appendix A.

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

Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **7 ppmvw**

4. Equivalent Allowable Emissions: **16.7** lb/hour **8.1** 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 @ 32°F; 100% load; TPY @ 59°F, 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **16.7** lb/hour **11.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 32°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **1.4 ppmvd**	4. Equivalent Allowable Emissions: **3** lb/hour **4.8** 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; 32°F; 100% load; TPY @ 59°F, 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **17 lb/hr**	4. Equivalent Allowable Emissions: **17** lb/hour **8.5** 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): **Oil firing - all loads; 1,000 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **17** lb/hour **20.5** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **GE, 1998; Golder**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PSD-IPS; Section 2.0; Appendix A.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 100% load; 59°F. Tons/yr based on 2,390 hrs/yr gas firing and 1,000 hrs/yr oil firing; 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: **10 lb/hr**	4. Equivalent Allowable Emissions: **10** lb/hour **17.0** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 20% opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; all loads; 3,390 hrs/yr. See Attachment PSD-IPS; Section 2.0; 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: **20** % 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 oil firing.**	

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: **01 Jan 2002**	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.**	

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): **FDEP 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: **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-IPS [ ] Not Applicable [ ] Waiver Requested	
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD-IPS [ ] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [X] Attached, Document ID: PSD-IPS [ ] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD-IPS [ ] 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-IPS [ ] Not Applicable	
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD-IPS [ ] 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):

Unreg. Emissions Activities - 1 Tank 1.5 M gallons

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**	[ ]

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

This emission unit information section addresses one 1.5 million gallon tank as unregulated emission units. NSPS Subpart Kb recordkeeping requirements are applicable; there is no emission limiting or work practice standards. See Attachment PSD-IPS.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):
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:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

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): **No. 2 Distillate Oil/Diesel**		
2. Source Classification Code (SCC): **A2505030090**	3. SCC Units: **1,000 gallons used**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **41,700**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment (limit to 200 characters): **Annual rate combined for both tanks based on inputs to CTs; 18,300 Btu/lb (LHV); and 7.1 lb/gal at 59°F.**		

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
VOC			NS

PART B

REPORT

1.0 INTRODUCTION

IPS Avon Park Corporation proposes to license, construct, and operate a nominal 510-megawatt (MW) power production facility, referred to as the IPS DeSoto Power Project, in an unincorporated area of DeSoto County, Florida (Figure 1-1). The site will be located on an about 20-acre tract near Arcadia, Florida. The project consists of three 170-MW dual-duel, General Electric Frame 7FA combustion turbines (CTs) that will use dry low-nitrogen oxide (NO_x) (DLN) combustion technology when operating on natural gas and water injection (for NO_x control) when operating on distillate fuel oil. The facility is designed for peaking service. The primary fuel for the combustion turbines 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 in Florida requires an air construction permit and prevention of significant deterioration (PSD) review approval. To assist in performing the necessary licensing activities, IPS Avon Park Corporation has contracted Golder Associates Inc. (Golder) to perform the necessary air quality assessments for determining the project's compliance with state and federal new source review (NSR) regulation, including PSD and nonattainment review requirements. The critical aspects of these assessments include the air quality impact analyses performed using an air dispersion model and the best available control technology (BACT) analyses performed to evaluate the selected emission control technology.

The proposed project will be a new air pollution source that will result in increases in air emissions in DeSoto County. The U.S. Environmental Protection Agency (EPA) has implemented regulations requiring a PSD review. PSD regulations are promulgated under 10 Code of Federal Regulations (CFR) Part 52.21 and implemented through delegation to the Florida Department of Environmental Protection (DEP). Florida's PSD regulations are codified in Rules 62-212.400, F.A.C. These regulations incorporate the EPA PSD regulations.

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

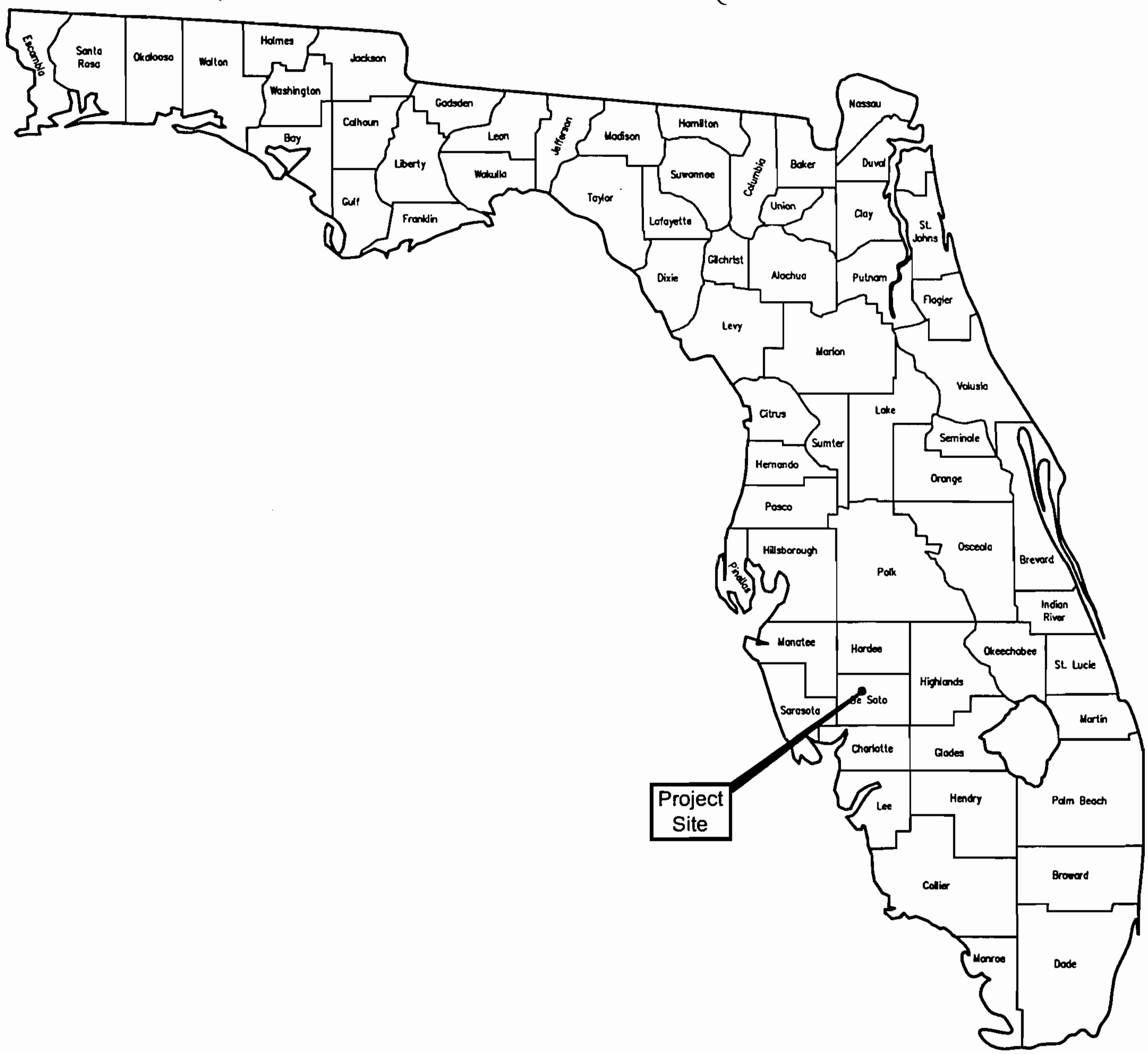
- Particulate matter (PM) as total suspended particulate matter (TSP),
- Particulate matter with aerodynamic diameter of 10 microns or less (PM_{10}),
- Nitrogen dioxide (NO_2),
- Sulfur dioxide (SO_2),
- Carbon monoxide (CO), and
- Volatile organic compounds (VOC).

DeSoto County has been designated as an attainment or unclassifiable area for all criteria pollutants [i.e., attainment: ozone (O_3), PM_{10}, SO_2, CO, and NO_2; unclassifiable: lead] and is classified as 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 facility, including air emissions and stack parameters.
- Section 3.0 provides a review of the PSD and nonattainment requirements applicable to the proposed 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 project with ambient air quality standards (AAQS), PSD increments, and good engineering practice (GEP) stack height regulations.
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility.

Called Steve 2/28



Golder Associates	Tampa, Florida	General Location	
Client / Project	CAD BY: CDT	SCALE: NTS	Job No. 993-9557
	CHK BY: CA	DATE: 01/07/00	FIGURE 1-1
	REV BY: –	FILE No.: gen-loc-1-1.dwg	

2.0 PROJECT DESCRIPTION

2.1 SITE DESCRIPTION

The project site, shown in Figure 2-1, consists of about 20 acres that are currently agricultural. There is minimal industrial, commercial, and residential development within a 3-km radius of the site. The plant elevation will be approximately 100 feet above sea level. The terrain surrounding the site is flat.

Natural gas will be supplied by a lateral pipeline connected to the Florida Gas Transmission (FGT) natural gas pipeline located north of the site. The site has access to transmission facilities from a 230 kV transmission line and electrical substation that is located to the southeast of the site. Water for the evaporative cooler, and NO_x control when firing oil, will be supplied by groundwater wells. Potable water and additional fire protection supply water will be served from groundwater wells or the City of Arcadia.

2.2 POWER PLANT

The proposed project will consist of three General Electric Frame 7FA CTs and associated facilities. The annual maximum capacity factor of the plant will be 39 percent, which is equivalent to operating 3,390 hours/year at full load. Natural gas will be used as the primary fuel, and fuel oil will be used as a backup fuel. Fuel oil usage will be limited to the equivalent of 1,000 hours/year at full load.

Plant performance with General Electric 7FA combustion turbines was developed for natural gas and oil; at 50-, 75-, and 100-percent load; and at 32°F, 59°F, and 95°F turbine inlet temperatures. Combustion turbine performance is based on a performance envelope developed from General Electric and has been adjusted to reflect degradation and performance improvements. In particular, the combustion turbine emission estimates accounts for 5 percent higher power output and a 6 percent degradation (see Appendix A). This 11 percent was used to increase mass flow of the turbine.

The CTs will be capable of operating from 50 to 100 percent of baseload. 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 baseload 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 one aboveground storage tank, each sized to hold approximately 36,000 barrels (1.5 million gallons).

Air emissions control will consist of using state-of-the-art dry low-NO_x burners in the CTs when firing natural gas. The General Electric Frame 7FA will be equipped with the General Electric dry low- 2.6 (DLN- NO_x) 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 optimum 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 General Electric 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).

2.3 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

The estimated maximum hourly emissions and exhaust information representative of the proposed CT design operating at baseload conditions (100-percent load), 75-percent load and 50-percent load conditions are presented in Tables 2-1 through 2-6. The information is presented in these tables for one unit simple cycle operation based on natural gas combustion and fuel oil combustion. The data are presented for turbine inlet temperatures of 32°F, 59°F, and 95°F. These temperatures represent the range of ambient temperatures that the CTs are most likely to experience.

The performance calculations for the operating conditions are given in Appendix A.

The pollutant gaseous emission concentrations and PM_{10} emission rates for the proposed CTs are as follows:

Pollutant	Natural Gas	Distillate Oil
NO_x, ppmvd @ 15% O_2	9	42
CO, ppmvd	12	20
VOC as CH_4, ppmvd (gas), ppmvw (oil)	1.4	7
SO_x as SO_2	Calculated Based on Fuel (1.0 grains S/100 SCF)	Calculated Based on Fuel (0.05% sulfur)
PM_{10} lb/hr (dry filterable)	10	17

The maximum short-term emission rates (lb/hr) generally occur at baseload, 32°F operation, where the CT has the greatest output and greatest fuel consumption.

Based on a turbine inlet temperature of 59°F, the emission rates used to calculate maximum potential annual emissions for the proposed facility for regulated air pollutants are presented in Table 2-7 for one and three CTs. To produce the maximum annual emissions, the CTs are assumed to operate at baseload for 3,390 hours (39 percent capacity factor) firing natural gas for 2,390 hours and fuel oil for 1,000 hours. The potential emissions are based on the 59°F turbine inlet air condition since it represents a nominal average between the higher emission levels at the 32°F turbine inlet condition (winter) and the infrequent 95°F turbine inlet condition (summer).

Process flow diagrams of the turbine operating at turbine inlet temperature of 95°F, 59°F, and 32°F are presented in Figures 2-2 and 2-4, respectively for the "F" Class CT.

Based on a review of the emission rates for natural gas and fuel oil combustion, the highest emission rates for the regulated pollutants generally occur when firing fuel oil. Combustion of natural gas and fuel oil result in slightly different exhaust flow gas rates and stack exit temperatures; however, the differences are minor. As a result of the higher emissions when firing oil, the air modeling analyses were based on determining maximum ground-level impacts with fuel oil.

As discussed in Section 6.0, the air modeling analyses that addressed compliance with ambient standards were based on modeling the CTs for the operating load and ambient temperature which produced the maximum impacts from the load impact analysis that was performed. Although the highest emission rates occur with low turbine inlet temperatures (i.e., 32°F) and baseload conditions, the lowest exhaust gas flow rates occur with a turbine inlet temperature of 95°F and 50 percent operating load. Since this low exhaust flow condition can result in potentially higher impacts due to lower plume rise (i.e., due to lower exit velocity and temperature), the load analysis included modeling the CTs for the following four scenarios designed to determine the maximum impacts for the project:

- Base operating load for the turbine inlet temperature of 32°F;
- Base operating load for the turbine inlet temperature of 95°F;
- A 50-percent operating load for the turbine inlet temperature of 32°F; and
- A 50-percent operating load for the turbine inlet temperature of 95°F.

2.4 SITE LAYOUT, STRUCTURES, AND STACK SAMPLING FACILITIES

Plot plan of the proposed facility is presented in Figure 2-5. 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.

Table 2-1. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Dry Low NO_x Combustors Firing Natural Gas -- Baseload for Simple Cycle Operation

		Operating and Emission Data[a] for Ambient Temperature		
Parameter		35°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,097	1,113	1,135
Velocity (ft/sec)		118.7	116.0	111.0
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	5.1	5.0	4.6
	Basis	1.0 grain S/100CF	1.0 grain S/100CF	1.0 grain S/100CF
PM/PM_{10}	lb/hr	10	10	10
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	66.7	64.1	59.9
	Basis	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2
CO	lb/hr	44.2	42.5	39.3
	Basis	12 ppmvd	12 ppmvd	12 ppmvd
VOC (as methane)	lb/hr	2.95	2.83	2.62
	Basis	1.4 ppmvd	1.4 ppmvd	1.4 ppmvd
Sulfuric Acid Mist	lb/hr	0.65	0.62	0.57
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-2. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Dry Low NO_x Combustors Firing Natural Gas -- 75 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Ambient Temperature		
		35°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,170	1,179	1,193
Velocity (ft/sec)		100.5	98.2	95.0
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	4.2	4.0	3.7
	Basis	1.0 grain S/100CF	1.0 grain S/100CF	1.0 grain S/100CF
PM/PM_{10}	lb/hr	10	10	10
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	54.4	52.4	48.3
	Basis	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2
CO	lb/hr	35.7	34.6	32.7
	Basis	12 ppmvd	12 ppmvd	12 ppmvd
VOC (as methane)	lb/hr	2.38	2.31	2.18
	Basis	1.4 ppmvd	1.4 ppmvd	1.4 ppmvd
Sulfuric Acid Mist	lb/hr	0.65	0.62	0.57
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-3. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Dry Low NO_x Combustors Firing Natural Gas -- 50 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Ambient Temperature 32°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,171	1,186	1,200
Velocity (ft/sec)		84.2	82.0	80.5
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	3.4	3.2	2.9
	Basis	1.0 grain S/100CF	1.0 grain S/100CF	1.0 grain S/100CF
PM/PM_{10}	lb/hr	10	10	10
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	43.4	40.8	38.3
	Basis	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2	9 ppmvd at 15% O_2
CO	lb/hr	30.0	28.9	27.8
	Basis	12 ppmvd	12 ppmvd	12 ppmvd
VOC (as methane)	lb/hr	2.00	1.93	1.85
	Basis	1.4 ppmvd	1.4 ppmvd	1.4 ppmvd
Sulfuric Acid Mist	lb/hr	0.52	0.49	0.45
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-4. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Water Injection Firing Distillate Fuel Oil -- Baseload for Simple Cycle Operation

		Operating and Emission Data[a] for Ambient Temperature		
Parameter		32°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,076	1,094	1,121
Velocity (ft/sec)		122.4	119.7	115.0
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	101.5	98.7	93.4
	Basis	0.05 % S	0.05 % S	0.05 % S
PM/PM_{10}	lb/hr	17.0	17.0	17.0
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	362.0	350.8	335.8
	Basis	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2
CO	lb/hr	74.4	71.4	66.2
	Basis	20 ppmvd	20 ppmvd	20 ppmvd
VOC (as methane)	lb/hr	16.7	16.2	15.3
	Basis	7 ppmvw	7 ppmvw	7 ppmvw
Sulfuric Acid Mist	lb/hr	15.6	15.1	14.3
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet; ppmvw = parts per million volume wet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-5. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Water Injection Firing Distillate Fuel Oil -- 75 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Ambient Temperature 32°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,170	1,176	1,186
Velocity (ft/sec)		101.0	99.6	97.0
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	82.6	80.1	74.8
	Basis	0.05 % S	0.05 % S	0.05 % S
PM/PM_{10}	lb/hr	17	17	17
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	296.7	285.3	267.8
	Basis	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2
CO	lb/hr	57.6	56.4	53.9
	Basis	20 ppmvd	20 ppmvd	20 ppmvd
VOC (as methane)	lb/hr	13.0	12.8	12.4
	Basis	7 ppmvw	5.4 ppmvw	5.5 ppmvw
Sulfuric Acid Mist	lb/hr	12.7	12.3	11.5
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet; ppmvw = parts per million volume wet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-6. Stack, Operating, and Emission Data for the Proposed GE 7FA Combustion Turbine with Water Injection Firing Distillate Fuel Oil -- 50 Percent Load for Simple Cycle Operation

Parameter		Operating and Emission Data[a] for Ambient Temperature 32°F	59°F	95°F
Stack Data (ft)				
Height		60	60	60
Diameter		22	22	22
Operating Data				
Temperature (°F)		1,200	1,200	1,200
Velocity (ft/sec)		85.7	83.3	81.5
Maximum Hourly Emission per Unit[b]				
SO_2	lb/hr	65.6	62.8	58.9
	Basis	0.05 % S	0.05 % S	0.05 % S
PM/PM_{10}	lb/hr	17	17	17
	Basis	Dry filterables	Dry filterables	Dry filterables
NO_x	lb/hr	236.4	224.0	209.3
	Basis	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2	42 ppmvd at 15% O_2
CO	lb/hr	72.2	69.8	67.5
	Basis	30 ppmvd	30 ppmvd	30 ppmvd
VOC (as methane)	lb/hr	10.9	10.5	10.3
	Basis	7 ppmvw	7 ppmvw	7 ppmvw
Sulfuric Acid Mist	lb/hr	10.0	9.6	9.0
	Basis	10% SO_2	10% SO_2	10% SO_2

Note: ppmvd = parts per million volume dry; O_2 = oxygen; S = sulfur; CF = cubic feet; ppmvw = parts per million volume wet

[a] Refer to Appendix A for detailed information.

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, mercury, arsenic, asbestos, vinyl chloride, and radionuclides.

Table 2-7. Maximum Potential Emissions for the IPS DeSoto Power Project - Tons/Year

		Natural Gas Firing[a] Load at 59 °F Turbine Inlet				Distillate Oil Firing[b] Load at 59 °F Turbine Inlet			Maximum Emissions
Pollutant	Units	100%	75%	50%	Units	100%	75%	50%	w/ oil-firing[c]
PM	1	17.0	17.0	17.0	1	8.5	8.5	8.5	20.5
SO_2	1	8.4	6.8	5.4	1	49.3	40.0	31.4	55.3
NO_x	1	108.6	88.8	69.2	1	175.4	142.6	112.0	252.0
CO	1	72.0	58.6	49.0	1	35.7	28.2	34.9	86.5
VOC	1	4.8	3.9	3.3	1	8.1	6.4	5.3	11.5
PM	3	50.9	50.9	50.9	3	25.5	25.5	25.5	61.4
SO_2	3	25.2	20.5	16.2	3	148.0	120.1	94.2	165.8
NO_x	3	325.8	266.5	207.6	3	526.2	427.9	336.0	755.9
CO	3	215.9	175.9	146.9	3	107.2	84.5	104.7	259.4
VOC	3	14.4	11.7	9.8	3	24.3	19.2	15.8	34.4

Note: [a] 3,390 hours per year operation.
[b] 1,000 hours per year operation.
[c] 2,390 hours of gas firing and 1,000 hours of oil firing.

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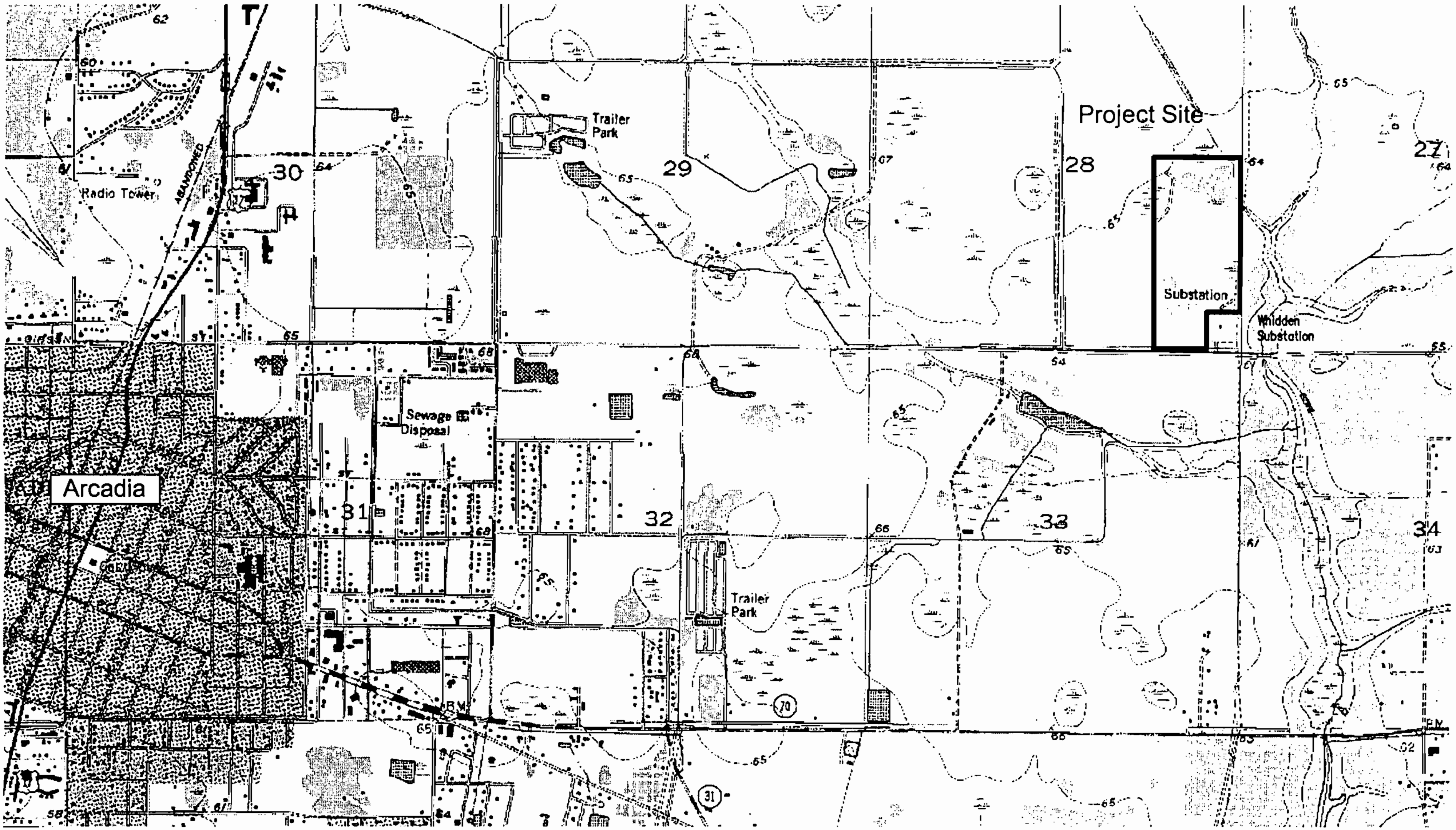


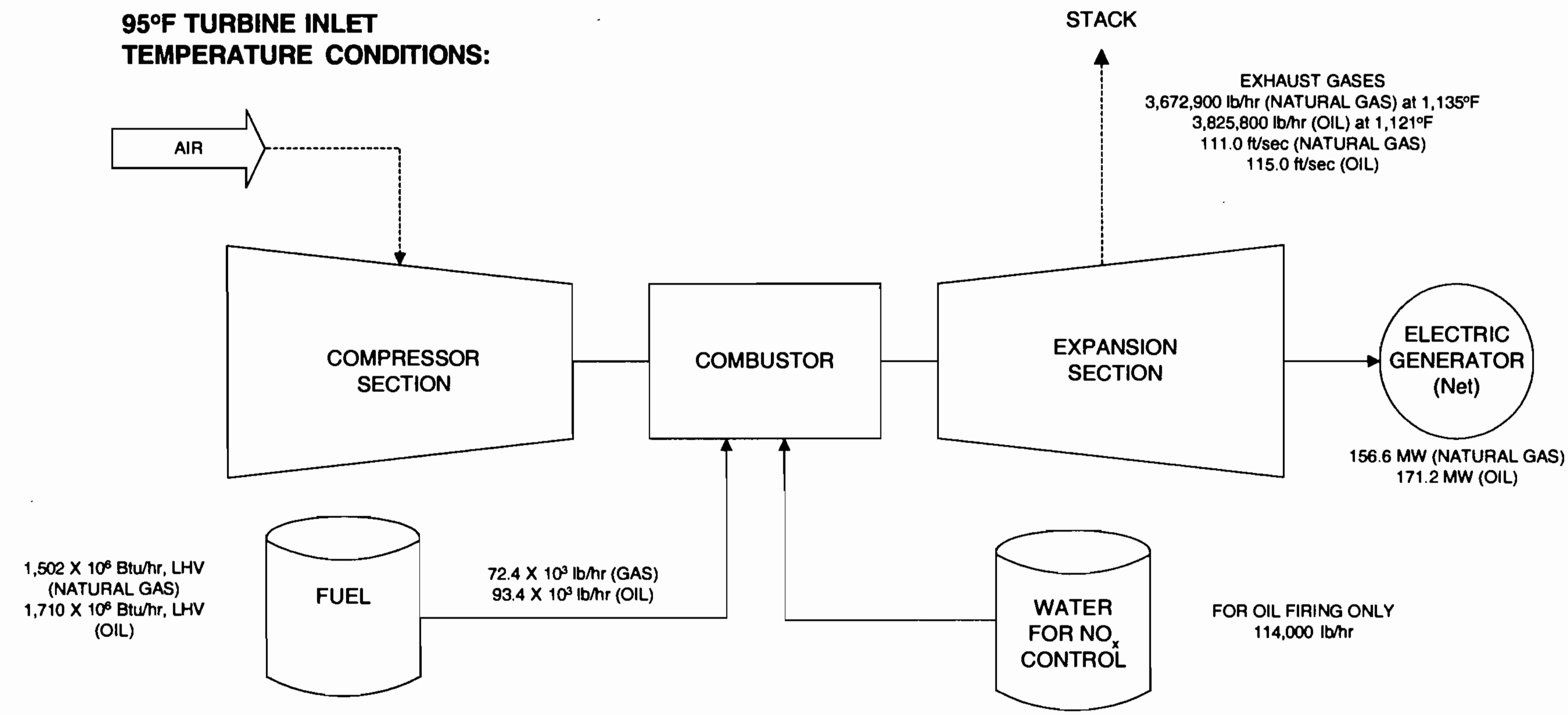
Golder Associates

Tampa, Florida

Site Location and Topographic Map

Client / Project

CAD BY: CDT	SCALE: 1"=2000'	Job No. 993-9557
CHK BY: CA	DATE: 01/10/00	FIGURE 2-1
REV BY: –	FILE No.:	



NOTE: SEE APPENDIX A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

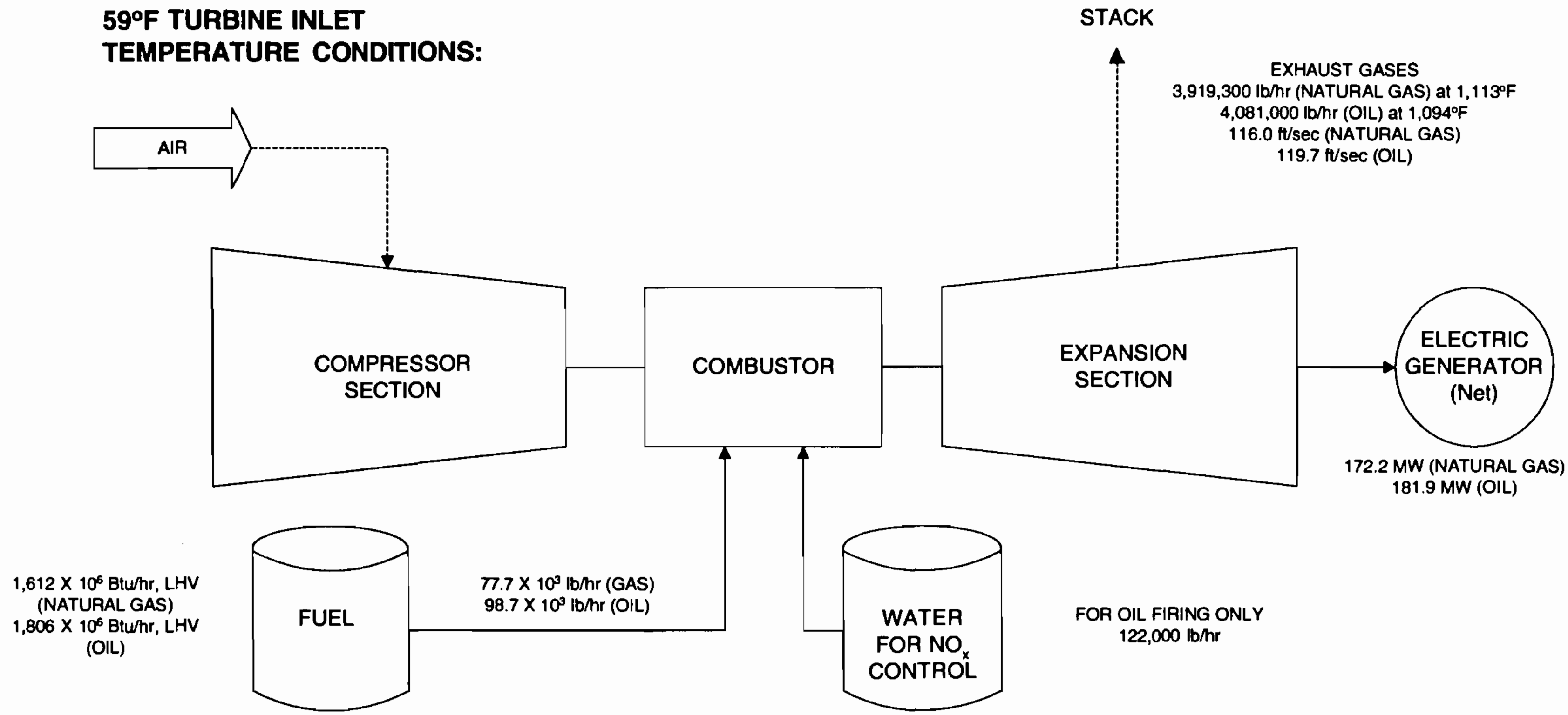
Figure 2-2
Simplified Flow Diagram of Proposed GE Frame 7FA Combustion Turbine
Baseload, Summer Design Conditions

Process Flow Legend	
Solid/Liquid	———▶
Gas	- - - - -▶
Steam	———▶

Filename: 9939557Y/F1/WP/FIGURES.VSD

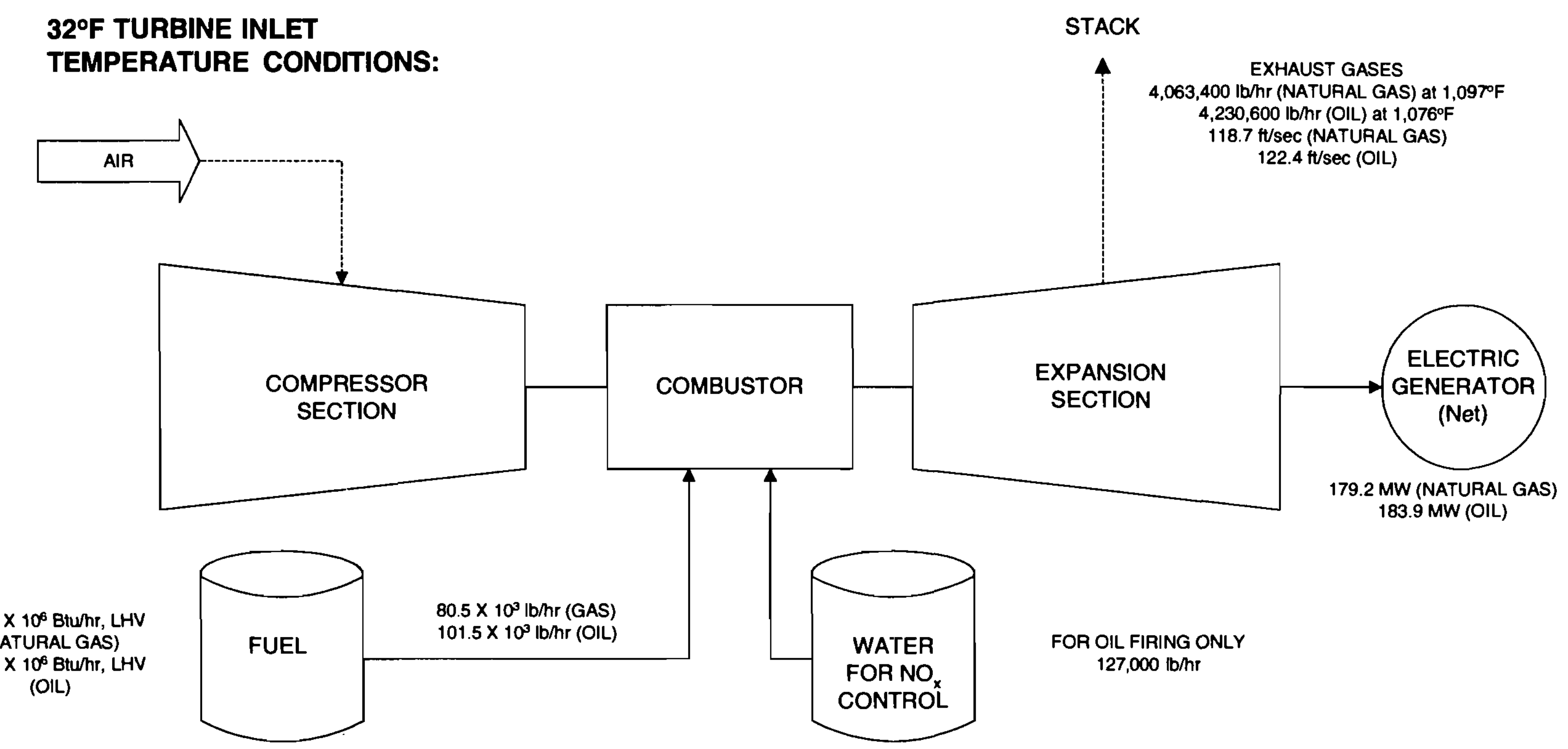
Date: 2/7/00

Golder Associates



NOTE: SEE APPENDIX A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

Figure 2-3 Simplified Flow Diagram of Proposed GE Frame 7FA Combustion Turbine Baseload, Annual Design Conditions	**Process Flow Legend** Solid/Liquid ——→ Gas - - - - → Steam ·········→	Filename: 9939557Y/F1/WP/FIGURES.VSD Date: 2/7/00	Golder Associates



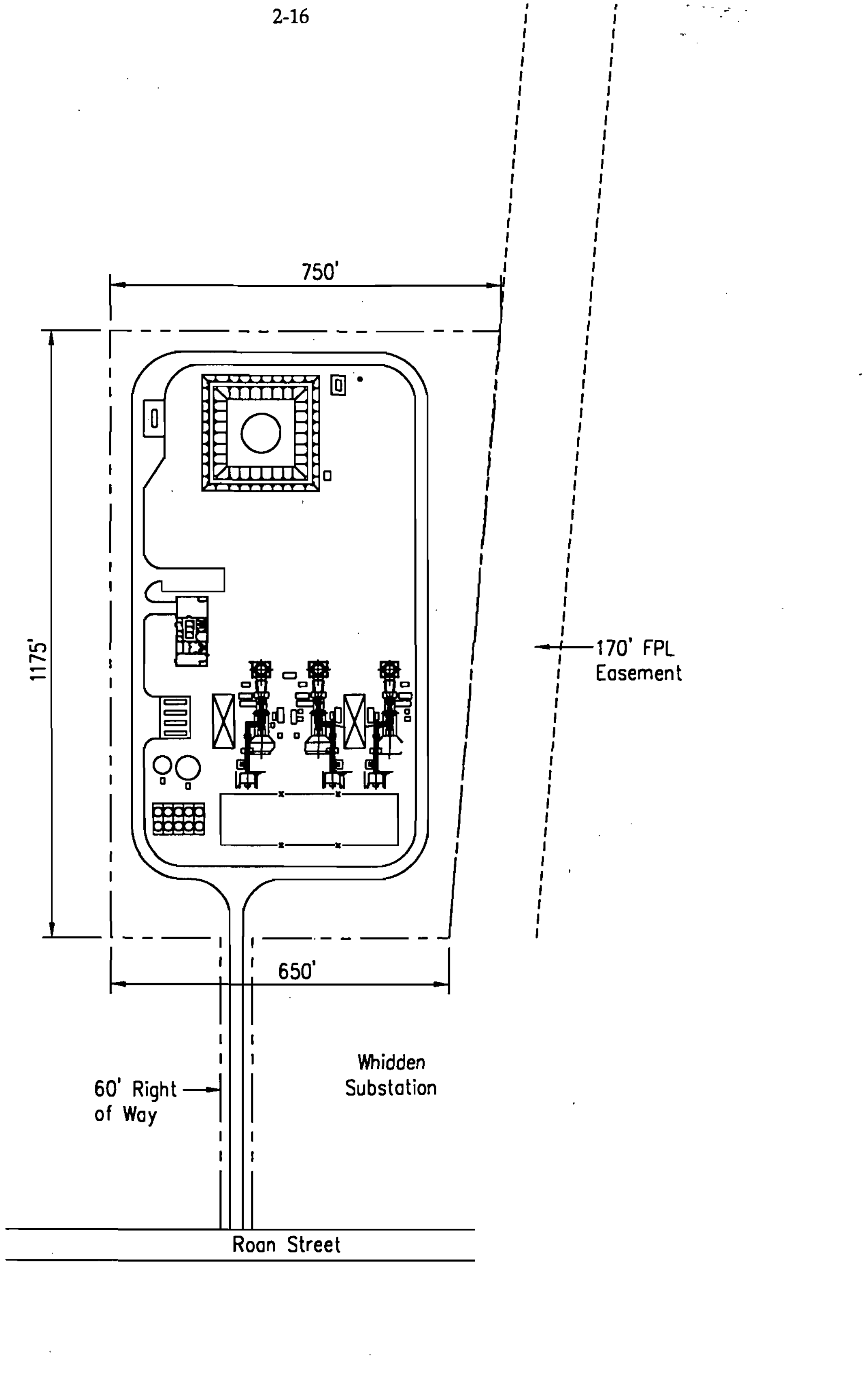
NOTE: SEE APPENDIX A FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

Figure 2-4
Simplified Flow Diagram of Proposed GE Frame 7FA Combustion Turbine
Baseload, Winter Design Conditions

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: 9939557Y/F1/WP/FIGURES.VSD
Date: 2/7/00

Golder Associates



Golder Associates

Tampa, Florida

Proposed Site Layout

Client / Project

IPS Avon Park Corporation

CAD BY:	CDT	SCALE: 1"=400'		Job No.	993-9557
CHK BY:	CA	DATE: 01/20/00		FIGURE	Figure 2-5
REV BY:	–	FILE No.: site-secondary.dwg			

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

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

3.1 NATIONAL AND STATE AAQS

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

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a 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 DEP.

A "major facility" is defined as any one 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 as regulations 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 increments.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted PSD regulations by reference [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 62-212.410, 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(40), 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 EPA's *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978) and in the *PSD Workshop Manual* (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

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

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

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limit that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. 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 (SILs) for Class I areas. The National Park Service (NPS) as the designated agency for oversight in air quality impacts to Class I areas has also recommended significant impact levels for PSD Class I areas. The EPA proposed Class I SILs 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 review, 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 in order to assist states in implementing the PSD permit process.

Various lengths of record for meteorological data can be used for impact analysis. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If 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 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 (Rule 62-275.700(1)(a), F.A.C.). The minor source baseline for NO_2 has been set as March 28, 1988 (Rule 62-275.700(3)(a), 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. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that Florida DEP may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 (Rule 62-212.400-3, F.A.C.).

3.2.5 SOURCE INFORMATION/GOOD ENGINEERING PRACTICE STACK HEIGHT

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

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by Florida DEP (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 five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height 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 (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 CAA Amendments of 1977, 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, and each fuel oil storage tank (2.8 million gallon capacity) will be subject to 40 CFR Part 60, Subpart Kb.

3.4.1.1 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 combustion turbines 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 oxygen and heat rate while sulfur dioxide emissions are limited to using a fuel with a sulfur content of 0.8 percent. In addition to emission limitations, there are requirements for notification, 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)(2) Notification of the date of initial start-up - no more than 60 days or less than 30 days prior to 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 the start-up, shutdown, and malfunction quarterly.

(c) Excess emissions reports - by the 30th day following end of quarter. (required even if no excess emissions occur)

(d) Maintain file of all measurements for two 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.

Gas - (2): daily monitoring required

3.4.1.2 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 tank 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 of the type of organic liquid in the tank.

3.4.2 FLORIDA RULES

The Florida DEP regulations for new stationary sources are covered in the F.A.C. The Florida DEP has adopted the EPA NSPS by reference in Rule 62-204.800(7); subsection (b)38 for stationary gas turbines and (b)15 for volatile organic liquid storage vessels. Therefore, the project is required to meet the same emissions, performance testings, monitoring, reporting, and record keeping as those described in Section 3.4.1. DEP has authority for implementing NSPS requirements in Florida.

3.4.3 FLORIDA AIR PERMITTING REQUIREMENTS

The Florida DEP 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, 62-4.052, 62-4.210, and 62-210.300(1), F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4.4 HAZARDOUS POLLUTANT REVIEW

The Florida DEP has published guidelines (DEP, 1995) to determine whether any emission of a potentially hazardous or toxic pollutant can pose a possible health risk to the public. Maximum concentrations for all regulated pollutants for which an ambient standard does not exist and all nonregulated hazardous pollutants can be compared to ambient reference concentrations (ARCs) for each applicable pollutant. If the maximum predicted concentrations for any hazardous pollutant is less than the corresponding ARC for each applicable averaging time, that emission is considered not to pose a significant health risk. The ARCs are not environmental standards but, rather, evaluation tools to determine if an apparent threat to the public health may exist. These levels are not used in permitting new sources.

3.4.5 LOCAL AIR REGULATIONS

DeSoto County does not have specific air regulations.

3.5 SOURCE APPLICABILITY

3.5.1 AREA CLASSIFICATION

The project site is located in DeSoto County, which has been designated by EPA and DEP as an attainment area for all criteria pollutants. DeSoto County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP) , and NO_2. The nearest Class I areas to the site is the Everglades National Park which is about 152 km (94 miles) from the site.

3.5.2 PSD REVIEW

3.5.2.1 Pollutant Applicability

The proposed project is considered to be a major facility because the emissions of several regulated pollutants are estimated to exceed 250 TPY; therefore, PSD review is required for any pollutant for which the emissions are considered major or exceed the PSD significant emission rates. As shown in Table 3-3, potential emissions from the proposed project will be major for PM (TSP), PM_{10}, SO_2, NO_x, CO, VOC, and sulfuric acid mist. Because the proposed project impacts for these pollutants are predicted to be below the significant impact levels, a modeling analysis incorporating the impacts from other sources is not required. (Note: EPA has promulgated changes to the PSD Rules to eliminate hazardous air pollutants (HAPs) from PSD review. The pollutants, vinyl chloride, mercury, asbestos, and beryllium, are no longer evaluated in PSD review.)

As part of the PSD review, a PSD Class I increment analysis is required if the proposed project's impacts are greater than the proposed EPA Class I significant impact levels. The nearest Class I areas to the plant site is about 151 km from the site. A PSD Class I increment-consumption analysis is required.

3.5.2.2 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 fuel oil storage tank will have a nominal storage capacity of 1.5 million gallons of No. 2 fuel oil. 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. The 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.

3.5.2.3 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 authorized 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.

If pre-construction monitoring data are required to be submitted, data collected at or near the project site can be submitted, based on existing air quality data or the collection of onsite data.

As shown in Table 3-4, the proposed plant's impacts are predicted to be below the applicable *de minimis* monitoring concentration levels and criteria.

3.5.2.4 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m [213 feet (ft)] high. The CT stacks for the project will be 60 ft. This stack height does 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 CTs' emissions caused by nearby structures are included in the modeling analysis.

3.5.3 NONATTAINMENT REVIEW

The project site is located in DeSoto 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 project 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 later of January 1, 2000, or the date on which the unit begins serving an electric generator (greater than 25 MW).

The permit would provide SO_2 and NO_x emission limitations and the requirement to hold 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. For the proposed project, SO_2 allowances will be obtained from the market.

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 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 ($\mu g/m^3$) Secondary Standard	AAQS ($\mu g/m^3$) Florida	PSD Increments ($\mu g/m^3$) Class I	PSD Increments ($\mu g/m^3$) 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, PM2.5 standards were introduced with a 24-hour standard of 65 g/m^3 (3-year average of 98th percentile) and an annual standard of 15 g/m^3 (3-year average at community monitors). These standards have been stayed by a court case against EPA and implementation of these standards are many years away pending EPA appeal.

[d] 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm or less. These have been stayed by a courtcase against EPA. EPA is appealing. The 1-hour standard of 0.12ppm is still applicable. FDEP has not yet adopted the new standards.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-272, 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] (μg/m3)
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
MWC Organics	NSPS	3.5x10^{-6}	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM

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.
MWC = Municipal waste combustor
MSW = Municipal solid waste

[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 IPS DeSoto Power Project Compared to the PSD Significant Emission Rates

Pollutant	Pollutant Emissions (TPY)		PSD Review
	Potential Emissions from Proposed Facility[a]	Significant Emission Rate	
Sulfur Dioxide	165.8	40	Yes
Particulate Matter [PM(TSP)]	61.4	25	Yes
Particulate Matter (PM_{10})	61.4	15	Yes
Nitrogen Dioxide	755.9	40	Yes
Carbon Monoxide	259.4	100	Yes
Volatile Organic Compounds	34.4	40	No
Lead	0.03	0.6	No
Sulfuric Acid Mist	25.4	7	Yes
Total Fluorides	0.09	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Mercury	0.0018	0.1	No
MWC Organics (as 2,3,7,8-TCDD)	$9.8X10^{-7}$	$3.5x10^{-6}$	No
MWC Metals (as Be, Cd)	0.01	15	No
MWC Acid Gaser (as HCl)	0.6	40	No

Note: NEG = Negligible.

[a] Based on emissions from operating at baseload at 59°F; firing natural gas and distillate fuel oil for 1,000 and 2,390 hours per year per turbine for a total of three CTs, respectively (Refer to Table 2-7).

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

	Concentration (μg/m3)	
Pollutant	Predicted Increase in Impacts[a]	*De Minimis* Monitoring Concentration
Sulfur Dioxide	1.0	13, 24-hour
Particulate Matter (PM_{10})	0.23	10, 24-hour
Nitrogen Dioxide	0.25	14, annual
Carbon Monoxide	1.3	575, 8-hour
Volatile Organic Compounds	45.9 TPY	100 TPY

Note: NA = not applicable.
NM = no ambient measurement method.
TPY = tons per year.

[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, VOC, and PM/PM_{10} (see Section 3.0). The maximum potential annual emissions of these pollutants from the proposed GE 7FA CTs are summarized below (see Table 2-7):

Pollutant Emissions (TPY)

Pollutant	3 GE 7FA CTs
NO_x	755.9
SO_2	165.8
CO	259.4
VOC	34.4
PM/PM_{10}	61.4

[a] Maximum emissions based on firing natural gas for 2,390 hours and distillate fuel oil for 1,000 hours at baseload conditions and 59°F.

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 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); and Rule 62-212.200(40), and Rule 62-214.410, F.A.C.]. 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 oxygen. For the CTs being considered for the project, the NSPS emission limit NO_x with the NSPS heat rate correction is 109.4 parts per million (ppm) on gas and 103.1 ppm on oil (corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent. The proposed NO_x emission limits for the project will be much lower than the NSPS.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 PROPOSED BACT

In recent permitting actions, FDEP has established BACT for heavy-duty industrial gas turbines. These decisions have included the use of advanced dry low-NO_x combustors for limiting NO_x and CO emissions and clean fuels (natural gas and distillate oil) for control of other emissions, including SO_2. The BACT proposed for the CTs is consistent with these FDEP permits. The proposed project will have two modes of operation (see Section 2.3) for which a BACT analysis has been performed. The results of the analysis have concluded the following controls as BACT for the project.

1. Natural Gas Fired. The CTs will utilize state-of-the-art dry low-NO_x combustion technology which will achieve gas turbine exhaust NO_x levels of no greater than 9 ppmvd corrected to 15 percent O_2. CO emissions will be limited to 12 ppmvd at baseload.
2. Fuel Oil Fired. The CT will utilize water injection to achieve gas turbine exhaust NO_x levels of no greater than 42 ppmvd corrected to 15 percent O_2. CO emissions will be limited to 20 ppmvd at baseload.

4.3.2 NITROGEN OXIDES

4.3.2.1 Introduction

The BACT analysis was performed for the following alternatives:

1. Advanced dry low-NO_x combustors at an emission rate of 9 ppmvd corrected to 15 percent O_2 when firing gas and 42 ppmvd (corrected) when firing oil.
2. Selective catalytic reduction (SCR) and advanced dry low-NO_x combustors at an emission rate of approximately 3.5 ppmvd corrected to 15 percent O_2 when firing natural gas and 16 ppmvd when firing oil.

Appendix B presents a discussion of NO_x control technologies and their feasibility for the project.

Dry low-NO_x combustor technology has recently 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 combustion turbines. Advanced in this context is the larger (over 150 MW) and more efficient (higher initial firing temperatures and lower heat rate) combustion turbines. This technology is truly pollution prevention since NO_x emissions are inhibited from forming.

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. The reaction occurs typically between 600°F and 750°F, which has limited SCR application to combined cycle units where such temperatures occur in the HRSG. Exhausts from simple cycle operation up to 1,200°F, thus limiting SCR application for this mode of operation. With the higher cost ceramic catalyst, temperatures up to 1,050°F are possible. Such SCR systems are referred to as "hot" SCR. To accommodate "hot" SCR in the "F" Class gas turbine, some gas cooling would be required to maintain temperatures below 1,050°F. In-duct cooling using about 110,000 acfm of ambient air would maintain temperatures at below 1,050°F with turbine flow of about 2,600,000 acfm and up to 1,200°F . This could be accomplished with an electric powered fan rated at about 200 kW. While such modifications are theoretically possible, such gas cooling and its effectiveness has not been demonstrated on a "F" Class simple cycle gas turbine. SCR has been primarily installed and operated on combined cycle facilities using catalysts with temperature ranges from 600-750°F and generally achieving 9 ppmvd (corrected to 15-percent O_2) or less while burning only natural gas.

Applications of SCR with oil firing are limited. Where oil firing has been attempted, catalyst poisoning and ammonium salt formation has occurred. 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 that does not react with NO_x is emitted directly and referred to as ammonia slip. In general, SCR manufacturers guarantee ammonia slip to be no more than 10 ppmvd; however, permitted limits in some applications have exceeded 25 ppmvd. While SCR is technically feasible for the project, SCR has not been applied to a simple cycle advanced combustion turbine of the size proposed for this project or to the amount of oil firing that may occur.

The recent permitting trend for advanced combustion turbines, even with combined cycle configuration, is the use of dry low-NO_x combustors. Indeed, most of the recent Florida projects have been permitted with this technology, including five projects in Florida (Florida Power & Light Martin Units 3 and 4; Central Florida Cogeneration Project; DeSoto Unit 3 Project, and City of Tallahassee Project), and FPL Fort Myers Repowering Project.

As discussed in Section 2.1, the proposed CTs will be fired primarily with natural gas. Distillate oil will be used as backup fuel not to exceed 1,000 hours per year. Table 4-1 presents a summary of emissions with dry low-NO_x combustors and with dry low-NO_x combustors and SCR assuming 39 percent operating capacity at an ambient temperature of 59°F. The NO_x removed using SCR would be 154 TPY when firing oil and natural gas. The NO_x removed when firing oil is based on 1,000 hours per year. The NO_x removed when firing natural gas is based on 2,390 hours of operation.

4.3.2.2 Proposed BACT and Rationale

The proposed BACT for the project is advanced dry low-NO_x combustion technology. The proposed NO_x emissions level using this technology is 9 ppmvd (corrected to 15 percent oxygen) when firing natural gas under baseload conditions. NO_x from oil firing will be controlled using water injection (42 ppmvd corrected to 15 percent oxygen). This combination of control technologies is proposed for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy grounds. Table 4-2 summarizes these considerations which favor the dry low-NO_x pollution prevention technology.
2. The estimated incremental cost of SCR is approximately $11,350 per ton of NO_x removed and is similar to cost for other projects that have rejected SCR as being unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered.
3. Additional environmental impacts would result from SCR operation, including emissions of ammonia; from secondary emissions (to replace the lost generation); and from the generation of hazardous waste (i.e., spent catalyst replacement). While NO_x emissions would be reduced by about 154 TPY per unit with SCR, the net emissions reduction would not be as great. There are three additional factors that must be considered:
   a. Ammonia slip would occur, and it may be as high as 47.7 TPY per unit.
   b. Additional particulate matter may be formed through the reaction of ammonia and sulfur oxides forming ammonium salts. As much as 17.2 TPY per unit additional particulate matter may be formed.
   c. SCR will require energy for system operation and reduce the efficiency of the combustion turbine. This lost energy would have to be replaced since the proposed project would be an efficient peaking power plant while operating. Any peaking power plants replacing this lost energy would be lower on the dispatch list and inevitably more polluting. Conservatively, this lost energy would result in the emissions of an additional 4.3 TPY of criteria pollutants. Additional emissions of carbon dioxide would also result.
   d. The "net" cost effectiveness cold be a high as $20,600 per ton of pollutant removed.
4. The energy impacts of SCR will reduce potential electrical power generation by more than 3.9 million kilowatt hours (kWh) per year. This amount of energy is sufficient to provide the monthly electrical needs of 322 residential customers.
5. The proposed BACT (i.e., dry low-NO_x combustion) provides the most cost effective control alternative, is pollution preventing, and results in low

environmental impacts (less than the significant impact levels). Dry low-NO_x combustion at the proposed emissions levels has been adopted previously in BACT determinations. Indeed, compared to conventional CTs, the proposed BACT will result in 10 to 15 percent less NO_x emission from the same amount of generation.

The analyses of economic, environmental, and energy impacts follow.

4.3.2.3 Impact Analysis

Economic--The total capital costs of SCR for the proposed plant are $5,868,336 per CT. The total annualized cost of applying SCR with dry low-NO_x combustion is $1,748,189. Appendix B contains the detailed cost estimates for the capital and annualized costs. The incremental cost effectiveness of adding SCR to the dry low-NO_x combustors and water injection (for oil firing) is estimated at $11,350 per ton of NO_x removed.

Environmental--The maximum predicted NO_x impacts using the dry low-NO_x technology are all 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. Indeed, the maximum annual impact for the project is 0.25 $\mu g/m^3$, which is 25 percent of the significant impact level. While additional controls beyond dry low-NO_x combustors (i.e., SCR and SCR with water injection) would reduce emissions, the effect will not be significant and much less than 1 percent of the PSD increment and the AAQS for the project.

The use of dry low-NO_x combustor technology is truly "pollution prevention". In contrast, use of SCR on the proposed project will cause emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate. Ammonia emissions associated with SCR are expected to be up to 10 ppm based on reported experience; previous permit conditions have specified this level. Indeed, ammonia emissions could be as high as 47.7 TPY/ per unit for the project. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10}; up to 17.2 TPY/per unit could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will reduce the available power from the project. This 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. These "secondary" emissions, coupled with potential emissions of ammonia and ammonium salts, are presented in Table 4-3. This table shows the emissions balance for the project with and without SCR. As shown, the net reduction in emissions with SCR when all criteria pollutants are considered will be 89 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted and were included in Table 4-3. As noted from this table, the emissions including CO_2 would be greater with SCR than that proposed using dry low-NO_x combustion technology.

The replacement of the SCR catalyst will create additional economic and environmental impacts since certain catalysts contain materials that are listed as hazardous chemical wastes under Resource Conservation and Recovery Act (RCRA) regulations (40 CFR 261). In addition, SCR will require the construction and maintenance of storage vessels of anhydrous or 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.

<u>Energy</u>--Significant energy penalties occur with SCR. With SCR, the output of the CT may be reduced by about 0.50 percent over that of advanced low-NO_x combustors. This penalty is the result of the SCR pressure drop, which would be about 2.5 inches of water and would amount to about 2,920,485 kWh per year in potential lost generation. The energy required by the SCR equipment would be about 949,200 kWh per yr. Taken together, the total lost generation and energy requirements of SCR of 3,869,685 kWh per year could supply the monthly electrical needs of about 322 residential customers. To replace this lost energy, an additional 37.5 x 10^{10} British thermal units per year (Btu/yr) or about 37.5 million cubic feet per year (ft^3/yr) of natural gas would be required.

Technology Comparison--The proposed project will use an advanced heavy-duty industrial gas turbine with advanced dry low-NO_x 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 dry low-NO_x combustors that prevent the formation of air pollutants within the combustion process, thereby eliminating the need for add-on controls that can have detrimental effects 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 GE Frame 7 FA advanced machine is about 170 MW compared to the 70 MW 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 lower 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 dry low-NO_x 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 are premixed prior to ignition. This level of control will result in NO_x emissions of about 0.04 lb/10^6 Btu, which is less than half of the emissions generated from conventional fossil fuel-fired steam generators.

Since the purpose of the project is to produce electrical energy, and CT technology is rapidly advancing, it is appropriate to compare the proposed emissions on an equivalent generation basis to that of a conventional CT. The heat rate of the GE 7FA machines will be about 9,360 Btu/kWh (LHV, 59°F, natural gas). In contrast, the heat rate for a new conventional CT is about 11,000 Btu/kWh. Therefore, the amount of total NO_x from the advanced CT will be more than 10-percent lower than a conventional turbine for the same amount of generation.

Also, the amount of NO_x control achieved by the dry low-NO_x combustor on an advanced CT is considerably higher than that achieved by a conventional CT. Because of the higher firing initial temperatures, the advanced CT results in greater NO_x emission formation. Since the advanced machine has higher firing temperatures, the NO_x emissions without the use of dry low-NO_x combustion technology are much higher than a conventional CT (greater than 180 ppmvd vs. 150 ppmvd). This results in an overall greater NO_x reduction on the advanced CT.

4.3.3 CARBON MONOXIDE

4.3.3.1 Introduction

Emissions of CO are dependent upon the combustion 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 (i.e., for oil firing). The CTs proposed for the project have designs to optimize combustion efficiency and minimize CO as well as NO_x emissions.

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

1. Combustion controls at 12 ppmvd when firing natural gas (at baseload) and 20 ppmvd when firing oil (at baseload); and
2. Oxidation catalyst at 80% removal; maximum annual CO emissions are 17 TPY per unit.

4.3.3.2 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 12 ppmvd when firing natural gas and 20 ppmvd when firing distillate oil at baseload conditions. 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 about $1.85 million per unit, with an analyzed cost of $585,000 per year per unit); and
3. Recent projects in Florida have been authorized with BACT emission limits of 25 ppmvd on gas and 90 ppmvd on oil.

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 30 ppmvd range and higher. Even the Northeast States for Coordinated Air Use Management (NESCAUM) has recognized a BACT level of 50 ppmvd for CO emissions. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

4.3.3.3 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $585,600 per unit, resulting in a cost effectiveness of greater than $7,500 per ton of CO removed. The cost effectiveness is based on 2,390 hours per year on natural gas and 1,000 hours per year of operation on oil. No costs are associated with combustion techniques since they are inherent in the design.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst. 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 ambient air quality standards. There would also be no secondary benefits, such as reductions in acidic deposition, to reducing CO.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 1,168,194 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 98 residential customers for a year. To replace this lost energy, about 1.1×10^{10} Btu/yr or about 11 million ft^3/yr of natural gas would be required.

4.3.4 VOLATILE ORGANIC COMPOUNDS

VOCs will be emitted by the CT as a result of incomplete combustion. The proposed BACT for VOC emissions will be the use of combustion technology and the use of clean fuels so that emissions will not exceed 1.4 ppmvd when firing natural gas and 7.0 ppmvw when firing distillate oil. These emission levels are 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.

4.3.5 PM/PM_{10}, SO_2 AND OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

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- or oil-fired CTs.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs {i.e., the grain loading associated with the maximum particulate emissions [about 10 pounds per hour (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 these pollutants from CTs, other than the inherent quality of the fuel. Clean fuels, natural gas and distillate oil represent BACT for these pollutants. The use of natural gas and very low sulfur (0.05%) fuel oil will limit emissions of SO_2.

For the nonregulated pollutants, none of the control technologies evaluated for other pollutants (i.e., SCR) would reduce such emissions; thus, natural gas and distillate oil represent BACT because of their inherently low contaminant content.

Table 4-1. NO_x Emission Estimates (TPY) of BACT Alternative Technologies (per Unit)

	Operating Mode[a]		
Alternative BACT Control Technologies	Oil	Gas	Total
NO_x Emission (TPY)			
Dry Low-NO_x (DLN) only	175.4	76.6	252.0
DLN with SCR[b]	68.2	29.8	98.0
Reduction	(107.2)	(46.8)	(154)
Basis of Emissions (ppmvd)			
DLN only	42	9	
DLN with SCR	16	3.5	
Hours of Operation	1,000	2,390	3,390

Note: DLN = Dry low-NO_x.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Emission rates were based on a "F" class combustion turbine operating at 100-percent capacity and firing natural gas for 2,390 hours and distillate fuel oil for 1,000 hours. Emission data are based on an ambient temperature of 50°F at maximum emission rates.

[b] Based on primary emissions with SCR; no account is made for additional emissions (secondary) due to lost energy from heat rate penalty and electrical usage for SCR operation (see Table 4-3).

Table 4-2. Comparison of Alternative BACT Control Technologies for NO_x (per Unit)

	Alternative BACT Control Technologies	
	DLN Only	SCR
Technical Feasibility	Feasible	Feasible for gas
Economic Impact[a]		
Capital Costs	included	$5,868,336
Annualized Costs	included	$1,748,189
Cost Effectiveness		
NO_x Removed (per ton of NO_x)	NA	$11,350
NO_x Removed (per ton of total pollutants)	NA	20,629
Environmental Impact[b]		
Total NO_x (TPY)	252	98
NO_x Reduction (TPY)	NA	(154)
Ammonia Emissions (TPY)	0	47.7
PM Emissions (TPY)	0	17.2
Secondary Emissions (TPY)	0	4.3
Net Emission Reduction (TPY)	NA	(84.8)
Energy Impacts[c]		
Energy Use (kWh/yr)	0	3,869,685
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	37,478
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	37
Energy Use (residential customers)	0	322

[a] See Appendix B for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table 4-3.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 3,390 hours per year. Lost energy is based on 0.5 percent of 175.06 MW. SCR electrical usage is based on 0.080 MWh per SCR system and 0.20 MWh for cooling fan.

Table 4-3. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction

Pollutants	Incremental Emissions (tons/year) of SCR Primary	Secondary	Total
Particulate	17.21	0.14	17.35
Sulfur Dioxide		0.05	0.05
Nitrogen Oxides	-153.97	2.50	-151.47
Carbon Monoxide		1.50	1.50
Volatile Organic Compounds		0.10	0.10
Ammonia	47.73		
Total:	-89.03	4.28	-84.74
Carbon Dioxide (additonal from gas firing)		2,373.60	2,373.60

Basis:

Lost Energy (mmBtu/year)	37,478

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NO_x 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

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.

A major source may waive the ambient monitoring analysis requirement if it can be demonstrated that the proposed source's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels. The maximum impacts of the proposed source are compared with the PSD *de minimis* concentrations in Table 3-4. As can be seen from Table 3-4, the proposed plant's maximum air quality impacts will be well below the *de minimis* concentrations for all applicable pollutants. For VOCs, the potential emission from the project are less than the *de minimis* criteria of 100 TPY; therefore, monitoring for ozone is not required.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 SIGNIFICANT IMPACT ANALYSIS APPROACH

The general modeling approach in this case followed EPA and Florida DEP modeling guidelines for determining compliance with AAQS and PSD increments. For all applicable pollutants that have emission increases that will exceed the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the project alone will result in predicted impacts that will exceed the EPA significant impact levels at any off-plant property areas in the vicinity of the plant.

If the project's impacts are above the significant impact levels, then a more detailed air modeling analysis that includes background sources is performed. Current Florida DEP policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable significant impact levels. Based on the screening modeling analysis results, additional modeling refinements with a denser receptor grid are performed, as necessary, to obtain the maximum concentration. Modeling refinements are performed with a receptor grid spacing of 100 meters (m) or less.

For this project, the significant impacts levels were estimated in the vicinity of the plant following Florida DEP policies.

Generally, if a new project also is within 150 km of a PSD Class I area, then a significant impact analysis is also performed for the PSD Class I area. EPA has proposed PSD Class I significant impact levels as rules but have not yet been finalized.

Because the proposed project site is approximately 152 km from the Everglades National Park (ENP) PSD Class I area, a significant impact modeling analysis has been performed. The Chassahowitzka National Wilderness Area, also a PSD Class I area, is 175 km from the proposed site.

6.2 PRECONSTRUCTION MONITORING ANALYSIS APPROACH

The general modeling approach in this case followed EPA and Florida DEP modeling guidelines for evaluating a project's impacts relative to the *de minimis* monitoring levels to determine the need to submit continuous monitoring data prior to construction. For all applicable pollutants that have emission increases that will exceed the PSD significant emission rate due to a proposed project, a *de minimis* impact analysis is performed to determine whether the project alone will result in predicted impacts that will exceed the EPA *de minimis* levels at any off-plant property areas in the vicinity of the plant. Current Florida DEP policies stipulate that the highest annual average and highest short-term concentrations are to be compared to the applicable *de minimis* monitoring levels.

A proposed major stationary facility or major modification may be 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.

For this project, the project's impacts were estimated in the vicinity of the plant for comparison to *de minimis* levels following Florida DEP policies. As presented in Section 5.0, since the estimated project's VOC emissions are lower than the *de minimis* VOC emission level, the project is exempt from preconstruction ambient monitoring requirements.

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 annual and the highest short-term concentrations for comparison are compared to the significant impact levels and *de minimis* levels.

If the project's impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations, and predict concentration for comparison to ambient standards. In general, when 5 years of meteorological data are used in the analysis, the highest annual and the highest, second-highest (HSH) short-term concentrations are compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated for a receptor field by:

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

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

To develop the maximum short-term concentrations for the proposed project, the modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. For this study, the only difference between the two modeling phases is the density of the receptor grid spacing employed when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record.

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentration from other years in the screening analysis are within 10 percent of the overall maximum concentration, then those other concentrations are refined as well. Typically, if the highest and HSH concentrations are in different locations, concentrations in both areas are refined.

Modeling refinements are performed for short-term averaging times by using a denser receptor grid, centered on the screening receptor at which the maximum concentration was predicted. The angular spacing between radials is 2 degrees and the radial distance interval between receptors is 100 m. Annual modeling refinements employ an angular spacing between radials of 2 degrees and a distance interval from 100 to 300 m, depending on the concentration gradient in the vicinity of the screening receptor to be refined. If the maximum screening concentration is located on the plant property boundary, additional plant boundary receptors are input, spaced at a 2-degree angular interval and centered on the screening receptor. The domain of the refinement grid will extend to all adjacent screening receptors. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred. This approach is used to ensure that a valid highest concentration is obtained. A more detailed description of the model, along with the emission inventory, meteorological data, and screening receptor grids are presented in the following sections.

6.3.2 MODEL SELECTION

The Industrial Source Complex Short-term (ISCST3, Version 99155) dispersion model (EPA, 1999) was used to evaluate the pollutant impacts due to the proposed CTs. 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 run in the rural or urban land use mode which 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 proposed plant site (see Figure 2-1), the rural dispersion coefficients were used in the modeling analysis.

The ISCST3 model was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times. A generic emission rate of 10 grams per second (g/s) was used as emissions for the proposed source. Maximum pollutant-specific air impacts were determined by multiplying the maximum pollutant-specific emission rate in pounds per hour (lb/hr) to the maximum predicted generic impact divided by 79.365 lb/hr (10 g/s).

6.3.3 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 from Fort Myer's page field and twice-daily upper air soundings from the National Weather Service (NWS) station at Ruskin. The 5-year period of meteorological data was from 1987 through 1991. The weather station at Fort Myers is located approximately 71 km (45 miles) south of the proposed plant site. The surface meteorological data from Fort Myers are assumed to be representative of the project site because both the project site and the weather station are located in similar topographical areas and are situated in central Florida to experience similar weather conditions, such as frontal passages.

6.3.4 EMISSION INVENTORY

A summary of the criteria pollutant emission rates, physical stack and stack operating parameters for the proposed CTs used in the air modeling analysis is presented in Tables 2-1 through 2-6. The emission and stack operating parameters presented for 32°F and 95°F ambient temperatures for both natural gas and distillate fuel oil were used in the modeling to determine the maximum air quality impacts for a range of possible operating conditions.

Six modeling scenarios per fuel type were considered:

1. base operating load for the ambient temperature of 32°F;
2. base operating load for the ambient temperature of 95°F;
3. 75 percent operating load for the ambient temperature of 32°F;
4. 75 percent operating load for the ambient temperature of 95°F;
5. 50 percent operating load for the ambient temperature of 32°F; and
6. 50 percent operating load for the ambient temperature of 95°F.

The proposed CTs will have a stack height of 60 feet and an inner stack diameter of 22 ft.

6.3.5 RECEPTOR LOCATIONS

For predicting maximum concentrations in the vicinity of the plant, a polar receptor grid comprised of 578 grid receptors was used. These receptors included 36 receptors located on radials extending out from the proposed CTs' stack locations. Along each radial, receptors were located at the plant property and distances of 0.1, 0.2, 0.3, 0.5, 0.7, 1.0, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 5.0, 7.0, 10.0, 12.0, 15.0, 20.0, 25.0, and 30.0 km from the middle CT stack of the three proposed CT stacks.

Modeling refinements were performed for the worst-case loads and fuel only, by employing a polar receptor grid with a maximum spacing of 100 m along each radial and an angular spacing between radials of 1 or 2 degrees.

Since the terrain surrounding the proposed plant site varies little from the stack base elevation of 25 ft-msl, the terrain was assumed to be flat and receptor elevations were set equal to the stack base elevation.

6.3.6 BUILDING DOWNWASH EFFECTS

The only significant structures in the vicinity of the proposed CT stacks are the proposed CT air filter inlets and the CT structures. The height and widths of these structures are as follows:

2 Km intervals

Dee Morse 303-964-2817

904-752-6494

1-888-611-6119

600-437-2346

Structure	Height (ft)	Width (ft)	Length (ft)
CT air inlet	47	36	36
CT structure	22	30	42

Building dimensions for the project's structures were entered into the EPA's Building Profile Input Program (BPIP, Version 95086) for the purpose of obtaining direction-specific building heights and widths for all downwash-affected sources. The direction-specific building dimensions were then input to the ISCST3 model as the building height and width for each of 36 ten-degree wind sectors. A summary of the direction-specific building dimensions used in the modeling is presented in Appendix C.

6.4 SIGNIFICANT IMPACT ANALYSIS RESULTS

6.4.1 SITE VICINITY

The modeling analysis results for the proposed CTs alone in the vicinity of the plant are summarized in Tables 6-2 through 6-5. The maximum pollutant concentrations predicted in the screening analysis for a single CT and two CTs firing natural gas are presented in Tables 6-2 and 6-3, respectively. Similarly, the maximum pollutant concentrations predicted for one and two CTs firing distillare fuel are presented in Tables 6-4 and 6-5, respectively.

Modeling refinements were performed in the site vicinity for the worst-case impacts for each pollutant/averaging time. These occurred during fuel oil firing. The refinement values are presented in the footnotes of Table 6-5.

As shown in the tables, the maximum predicted PM, SO_2, NO_x, and CO impacts due to the proposed CTs are all below the significant impact levels. Because the proposed source will not have a significant impact upon the air quality in the vicinity of the plant site, more detailed modeling analyses for determining compliance with the AAQS and allowable PSD Class II increments are not required.

The maximum predicted PM, SO_2, NO_x, and CO impacts due to the proposed CTs are also below the *de minimis* monitoring levels. Because the proposed source will not have predicted impacts greater than *de minimis* levels, preconstruction monitoring data are not required to be submitted as part of the PSD review.

6.4.2 AT THE ENP PSD CLASS I AREA

The modeling analysis results for the proposed CTs alone at the ENP are summarized in Tables 6-6 through 6-9. The maximum pollutant concentrations predicted in the screening analysis for a single CT and two CTs firing natural gas are presented in Tables 6-6 and 6-7, respectively. A summary of maximum pollutant concentrations predicted for one and two CTs firing distillate oil are presented in Tables 6-8 and 6-9, respectively.

As shown in the tables, the maximum predicted SO_2, NO_2, and PM impacts due to the proposed CTs are all below EPA's proposed PSD Class I significant impact levels. Therefore, more detailed modeling analyses for determining compliance with allowable PSD Class I increments are not required for these pollutants.

A summary of the ISCST3 model results for each year are presented in Appendix D. An example of the model input file are also provided in Appendix D.

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.
Source: EPA, 1995.

Table 6-2. Maximum Pollutant Concentrations Predicted for One Proposed Combustion Turbine on Natural Gas, at Site Vicinity

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature							Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)					
	Base Load		75% Load		50% Load		Averaging	Base Load		75% Load		50% Load	
Pollutant	32°F	95°F	32°F	95°F	32°F	95°F	Time	32°F	95°F	32°F	95°F	32°F	95°F
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0188	0.0171	0.0216	0.0223	0.0258	0.0262
							24-Hour	0.2501	0.2391	0.2711	0.3219	0.3475	0.3544
							8-Hour	0.4559	0.4215	0.5193	0.5447	0.6571	0.6646
							3-Hour	0.8812	0.8701	0.9208	0.9620	1.3896	1.3965
							1-Hour	1.7999	1.6191	2.1290	2.2379	2.5523	2.6694
SO_2	5.1	4.6	4.2	3.7	3.4	2.9	Annual	0.001	0.001	0.001	0.001	0.001	0.001
							24-Hour	0.02	0.01	0.01	0.02	0.01	0.01
							3-Hour	0.06	0.05	0.05	0.04	0.06	0.05
NO_x	66.7	59.9	54.4	48.3	43.4	38.3	Annual	0.02	0.01	0.01	0.01	0.01	0.01
PM_{10}	10.0	10.0	10.0	10.0	10.0	10.0	Annual	0.002	0.002	0.003	0.003	0.003	0.003
							24-Hour	0.03	0.03	0.03	0.04	0.04	0.04
CO	44.2	39.3	35.7	32.7	30.0	27.8	8-Hour	0.3	0.2	0.2	0.2	0.2	0.2
							1-Hour	1.0	0.8	1.0	0.9	1.0	0.9

(1) Concentrations are based on highest predicted concentrations using five years of meteorological data consisting of surface and upper air data from Ft. Myers and Ruskin, respectively, for 1987-91.

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.

Table 6-3. Maximum Pollutant Concentrations Predicted for 3 Simple-Cycle Combustion Turbines on Natural Gas Compared to EPA Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)						EPA Significant Impact Levels (ug/m^3)
		Base Load		75% Load		50% Load		
		32°F	95°F	32°F	95°F	32°F	95°F	
SO_2	Annual	0.004	0.003	0.003	0.003	0.003	0.003	1
	24-Hour	0.05	0.04	0.04	0.05	0.04	0.04	5
	3-Hour	0.17	0.15	0.15	0.13	0.18	0.15	25
NO_x	Annual	0.047	0.039	0.044	0.041	0.042	0.038	1
PM_{10}	Annual	0.007	0.006	0.008	0.008	0.010	0.010	1
	24-Hour	0.09	0.09	0.10	0.12	0.13	0.13	5
CO	8-Hour	1	1	1	1	1	1	500
	1-Hour	3	2	3	3	3	3	2,000

(1) Concentrations are based on highest predicted concentrations using five years of meteorological data consisting of surface and upper air data from Ft. Myers and Ruskin, respectively, for 1987-91.

Table 6-4. Maximum Pollutant Concentrations Predicted for One Proposed Combustion Turbine on Fuel Oil, at Site Vicinity

Pollutant	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature: Base Load 32°F	Base Load 95°F	75% Load 32°F	75% Load 95°F	50% Load 32°F	50% Load 95°F	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1): Base Load 32°F	Base Load 95°F	75% Load 32°F	75% Load 95°F	50% Load 32°F	50% Load 95°F
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0185	0.0192	0.0213	0.0219	0.0250	0.0271
							24-Hour	0.2489	0.2533	0.2703	0.3185	0.3418	0.3539
							8-Hour	0.4460	0.4661	0.5170	0.5425	0.6768	0.6620
							3-Hour	0.9547	0.8843	0.9168	0.9462	1.0312	1.3941
							1-Hour	1.7150	1.8570	2.1276	2.2228	2.5190	2.6290
SO_2	101.5	93.4	82.6	74.8	65.6	58.9	Annual	0.024	0.023	0.022	0.021	0.021	0.020
							24-Hour	0.32	0.30	0.28	0.30	0.28	0.26
							3-Hour	1.22	1.04	0.95	0.89	0.85	1.03
NO_x	362.0	335.8	296.7	267.8	236.4	209.3	Annual	0.08	0.08	0.08	0.07	0.07	0.07
PM_{10}	17.0	17.0	17.0	17.0	17.0	17.0	Annual	0.004	0.004	0.005	0.005	0.005	0.006
							24-Hour	0.05	0.05	0.06	0.07	0.07	0.08
CO	74.4	66.2	57.6	53.9	72.2	67.5	8-Hour	0.4	0.4	0.4	0.4	0.6	0.6
							1-Hour	1.6	1.5	1.5	1.5	2.3	2.2

(1) Concentrations are based on highest predicted concentrations using five years of meteorological data consisting of surface and upper air data from Ft. Myers and Ruskin, respectively, for 1987-91.

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.

Table 6-5. Maximum Pollutant Concentrations Predicted for 3 Simple-Cycle Combustion Turbines on Fuel Oil Compared to EPA Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)						EPA Significant Impact Levels (ug/m^3)
		Base Load		75% Load		50% Load		
		32°F	95°F	32°F	95°F	32°F	95°F	
SO_2	Annual	0.071(2)	0.07	0.07	0.06	0.06	0.06	1
	24-Hour	0.95(2)	0.9	0.8	0.9	0.8	0.8	5
	3-Hour	3.66(2)	3.1	2.9	2.7	2.6	3.1	25
NO_x	Annual	0.25(2)	0.2	0.2	0.2	0.2	0.2	1
PM_{10}	Annual	0.01	0.01	0.01	0.01	0.02	.017(2)	1
	24-Hour	0.2	0.2	0.2	0.2	0.2	.23(2)	5
CO	8-Hour	1.3	1.2	1.1	1.1	1.8(2)	1.7	500
	1-Hour	4.8	4.6	4.6	4.5	6.9(2)	6.7	2,000

(1) Concentrations are based on highest predicted concentrations using five years of meteorological data consisting of surface and upper air data from Ft. Myers and Ruskin, respectively, for 1987-91.

(2) Refined concentration

Table 6-6. Maximum Pollutant Concentrations Predicted for One Proposed Combustion Turbine on Natural Gas at the Everglades National Park PSD Class I Area

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature							Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)					
	Base Load		75% Load		50% Load		Averaging	Base Load		75% Load		50% Load	
Pollutant	32°F	95°F	32°F	95°F	32°F	95°F	Time	32°F	95°F	32°F	95°F	32°F	95°F
Generic	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0014	0.0014	0.0015	0.0016	0.0017	0.0018
(10 g/s)							24-Hour	0.0467	0.0416	0.0511	0.0527	0.0571	0.0587
							8-Hour	0.1276	0.1223	0.1371	0.1415	0.1544	0.1582
							3-Hour	0.2195	0.2073	0.2415	0.2493	0.2698	0.2758
							1-Hour	0.4339	0.4146	0.4669	0.4783	0.5077	0.5160
SO_2	5.1	4.6	4.2	3.7	3.4	2.9	Annual	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
							24-Hour	0.003	0.002	0.003	0.002	0.002	0.002
							3-Hour	0.01	0.01	0.01	0.01	0.01	0.01
NO_x	66.7	59.9	54.4	48.3	43.4	38.3	Annual	0.001	0.001	0.001	0.001	0.001	0.001
PM_{10}	10.0	10.0	10.0	10.0	10.0	10.0	Annual	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
							24-Hour	0.01	0.01	0.01	0.01	0.01	0.01
CO	44.2	39.3	35.7	32.7	30.0	27.8	8-Hour	0.1	0.1	0.1	0.1	0.1	0.1
							1-Hour	0.2	0.2	0.2	0.2	0.2	0.2

(1) Concentrations are based on highest predicted concentrations using five years of meteorological data consisting of surface and upper air data from Ft. Myers and Ruskin, respectively, for 1987-91.

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 emiss to the modeled emission rate of 10 g/s.

Table 6-7. Maximum Pollutant Concentrations Predicted for 3 Simple-Cycle Combustion Turbines on Natural Gas Compared to Proposed EPA PSD Class I Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)						Proposed EPA Class I Significant Impact Levels (ug/m^3)
		Base Load		75% Load		50% Load		
		32°F	95°F	32°F	95°F	32°F	95°F	
SO_2	Annual	0.0003	0.0002	0.0002	0.0002	0.0002	0.0002	0.1
	24-Hour	0.009	0.007	0.008	0.007	0.007	0.006	0.2
	3-Hour	0	0.0	0.0	0.0	0.0	0.0	1.0
NO_x	Annual	0.00	0.003	0.003	0.003	0.003	0.003	0.1
PM_{10}	Annual	0.00	0.001	0.001	0.001	0.001	0.001	0.2
	24-Hour	0.0	0.02	0.02	0.02	0.02	0.02	0.3

(1) Concentrations are based on highest predicted concentrations using five years of meteorological data consisting of surface and upper air data from Ft. Myers and Ruskin, respectively, for 1987-91.

Table 6-8. Maximum Pollutant Concentrations Predicted for One Proposed Combustion Turbine on Fuel Oil at the Everglades National Park PSD Class I Area

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature							Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)					
	Base Load		75% Load		50% Load		Averaging	Base Load		75% Load		50% Load	
Pollutant	32°F	95°F	32°F	95°F	32°F	95°F	Time	32°F	95°F	32°F	95°F	32°F	95°F
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0014	0.0014	0.0015	0.0016	0.0017	0.0018
							24-Hour	0.0457	0.0472	0.0509	0.0521	0.0562	0.0579
							8-Hour	0.1261	0.1292	0.1368	0.1396	0.1517	0.1570
							3-Hour	0.2160	0.2231	0.2407	0.2463	0.2655	0.2738
							1-Hour	0.4285	0.4393	0.4658	0.4739	0.5016	0.5132
SO_2	101.5	93.4	82.6	74.8	65.6	58.9	Annual	0.002	0.002	0.002	0.001	0.001	0.001
							24-Hour	0.06	0.06	0.05	0.05	0.05	0.04
							3-Hour	0.28	0.26	0.25	0.23	0.22	0.20
NO_x	362.0	335.8	296.7	267.8	236.4	209.3	Annual	0.01	0.01	0.01	0.01	0.01	0.00
PM_{10}	17.0	17.0	17.0	17.0	17.0	17.0	Annual	0.000	0.000	0.000	0.000	0.000	0.000
							24-Hour	0.01	0.01	0.01	0.01	0.01	0.01
CO	74.4	66.2	57.6	53.9	72.2	67.5	8-Hour	0.1	0.1	0.1	0.1	0.1	0.1
							1-Hour	0.4	0.4	0.3	0.3	0.5	0.4

(1) Concentrations are based on highest predicted concentrations using five years of meteorological data consisting of surface and upper air data from Ft. Myers and Ruskin, respectively, for 1987-91.

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.

Table 6-9. Maximum Pollutant Concentrations Predicted for 3 Simple-Cycle Combustion Turbines on Fuel Oil Compared to Proposed EPA PSD Class I Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1): Base Load 32°F	Base Load 95°F	75% Load 32°F	75% Load 95°F	50% Load 32°F	50% Load 95°F	Proposed EPA Class I Significant Impact Levels (ug/m^3)
SO_2	Annual	0.005	0.005	0.005	0.004	0.004	0.004	0.1
	24-Hour	0.18	0.17	0.16	0.15	0.14	0.13	0.2
	3-Hour	0.8	0.8	0.8	0.7	0.7	0.6	1.0
NO_x	Annual	0.02	0.02	0.02	0.02	0.02	0.01	0.1
PM_{10}	Annual	0.001	0.001	0.001	0.001	0.001	0.001	0.2
	24-Hour	0.03	0.03	0.03	0.03	0.04	0.04	0.3

(1) Concentrations are based on highest predicted concentrations using five years of meteorological data consisting of surface and upper air data from Ft. Myers and Ruskin, respectively, for 1987-91.

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 INTRODUCTION

The additional impact analysis addresses the potential impacts of the new power facility on vegetation, soils, and wildlife of the surrounding area and the nearest Class I area. The nearest Class I area is the Everglades National Park, located approximately 152 km south of the proposed plant. Because the facility is subject to the PSD NSR requirements for SO_2, PM_{10}, NO_2, CO, and sulfuric acid emissions, the additional impact analysis were performed for these pollutants. The analyses also addressed impacts associated with the project firing natural gas and backup distillate fuel oil.

According to the modeling results presented in Section 6.0, the maximum air quality impacts predicted for the project are well below the EPA's Class II significant impact levels, the PSD Class II increments, and the AAQS. The maximum air quality impacts predicted for the project are also below the EPA's Class I significant impact levels and the PSD Class I increments. As a result, regardless of the existing conditions in the vicinity of the site or in the Class I areas, the proposed project will not result in any significant adverse effects upon these areas.

7.2 SOIL, VEGETATION, AND AQRV ANALYSIS METHODOLOGY

As shown in Section 6.0, the maximum air quality impacts for the project were predicted in the vicinity of the project and in the Class I area. The analysis involved predicting worst-case maximum short- and long-term concentrations of pollutants and comparing them to the lowest observed effect levels for AQRVs or analogous organisms. In conducting the assessment, several assumptions were made to assess the pollutant interaction with the different matrices (i.e., vegetation, soils, wildlife, and aquatic environment).

A screening approach was used to evaluate potential effects that compared the maximum predicted ambient concentrations of air pollutants of concern with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the vicinity of the plant and the Class I area. It was recognized that effects threshold information is not available for all species found in the ENP, although studies have been performed on a few of the common species and on other similar species which can be used as models.

7.3 IMPACTS TO PLANT VICINITY SOILS AND VEGETATION

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.

Maximum predicted concentrations of SO_2, PM_{10}, NO_2, and CO in the vicinity of the project site are at least an order of magnitude lower than the EPA Class II significant impact levels (see Table 6-4); therefore, no significant impacts associated with facility operations are expected. The predicted concentrations are less than 1 percent of the AAQS. Since the AAQS are designed to protect the public welfare, including effects on soils and vegetation, no detrimental effects on soils or vegetation should occur in this area.

7.4 CLASS I AREA IMPACT ANALYSIS

7.4.1 IDENTIFICATION OF AQRV AND METHODOLOGY

An AQRV analysis was conducted to assess the potential risk to AQRVs of the ENP due to the modeled increase in emissions from the proposed facility. 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 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).

Except for visibility, AQRVs were not specifically defined. However, odor, soil, flora, fauna, cultural resources, geological features, water, and climate generally have been identified by land managers as AQRVs. Since specific AQRVs have not been identified for the ENP, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found in the ENP.

Vegetation type AQRVs and their representative species types have been defined as:

- Marshlands - black needlerush, saw grass, salt grass, and salt marsh cordgrass
- Marsh Islands - cabbage palm and eastern red cedar
- Estuarine Habitat - black needlerush, salt marsh cordgrass, and wax myrtle
- Hardwood Swamp - red maple, red bay, sweet bay, and cabbage palm
- Upland Forests - live oak, scrub oak, longleaf pine, slash pine, wax myrtle, and saw palmetto
- Mangrove Swamp - red, white, and black mangrove

Wildlife AQRVs have been identified as endangered species, waterfowl, marsh and waterbirds, shorebirds, reptiles, and mammals.

A screening approach was used that compared the maximum predicted ambient concentration of air pollutants of concern in the ENP (Table 7-1) with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted that specifically addressed the effects of air contaminants on plant species reported to occur in the park. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens, and species of the hardwood swamplands and mangrove forest, few specific citations that addressed these species were found. It is recognized that effect threshold information is not available for all species found in the ENP, although studies have been performed on a few of the common species and on other similar species that can be used as indicators of effects.

7.4.2 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 ENP 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. Entisols are shallow sandy soils overlying limestone, commonly found in sandhills and xeric 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 these soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the ENP from the Martin County facility emissions precludes any significant impact on soils.

7.4.3 VEGETATION

7.4.3.1 General

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. This is a conservative approach.

The concentration of the pollutant, duration of exposure, and frequency of exposures influence the response of vegetation and wildlife to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively low ground-level concentrations which occur during certain meteorological conditions interspersed with long periods of extremely low to no ground-level concentrations. If there are any effects of stack emissions on plants and animals 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.

7.4.3.2 SO_2

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.

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 $\mu g/m^3$. Background concentrations in South Florida (Dade County) reported in 1999 averaged 0.001 $\mu g/m^3$, with a maximum of 0.003 $\mu g/m^3$. Observed SO_2 effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-2 and 7-3, respectively.

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 $\mu g/m^3$. Resistant species (injured at concentrations above 2,100 $\mu g/m^3$ 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/m³ SO_2 for 8 hours were not visibly damaged. This finding supports 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/m³.

Two lichen species indigenous to Florida 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/m³ for 6 hours/week for 10 weeks (Hart et al., 1988).

The maximum 24-hour SO_2 concentrations predicted within the Class I area due to the project only are 0.009 μg/m³ when operating with natural gas and 0.18 μg/m³ when firing distillate fuel oil. When added to the maximum background concentration of 0.003 μg/m³, total SO_2 impacts are 0.012 and 0.183 μg/m³, for natural gas and distillate fuel oil, respectively. These levels are much lower than those known to cause damage to test species. Under worst-case scenarios when the plant is operating on backup fuel, the maximum 24-hour SO_2 concentrations predicted within the Class I area are only 0.04 to 0.08 percent of those that caused damage to the most sensitive lichens. Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 μg/m³ 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/m³ SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979). 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.

7.4.3.3 PM_{10}

Although information pertaining to the effects of particulate matter on plants is scarce, some results are available. Ten species of native Indian plants were exposed to levels of particulate matter that ranged from 210 to 366 μg/m³ 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 particulate matter lower than 163 μg/m^3 did not appear to be injurious to the tested plants (Mandoli and Dubey, 1988).

By comparison of these published toxicity values for particulate matter exposure (i.e., concentrations for an 8-hour averaging time), the possibility of plant damage in the ENP can be determined. The maximum predicted 8-hour PM_{10} concentration in the park due to the project only is 0.06 μg/m^3 when firing natural gas, and 0.10 μg/m^3 when firing distillate fuel oil (see Table 7-1). When added to the average background concentrations recorded in the vicinity of the NP (28 μg/m^3), the resultant concentrations are well below the lower threshold value that reportedly affects plant foliage. When added to the maximum PM10 concentrations recorded in the vicinity of the NP (57 μg/m^3), the worst case scenario concentrations are 57.06 and 57.1 μg/m^3 when firing natural gas or fuel oil, respectively. In any event, since the project contributes <1 μg/m^3, 8-hour average impact, to the total predicted impacts, no effects to vegetative AQRVs are expected from the project.

7.4.3.4 NO_2

Nitrogen dioxide (NO_2) is another emission of concern for the proposed plant. 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 μg/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 μg/m^3 for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

Short term (8 hour averaging time) predicted NO_x emissions in the Class I area due to the project only are 0.32 and 1.7 μg/m^3 for natural gas and fuel oil, respectively. When added to the maximum background NO_2 concentrations reported in the vicinity of the ENP (0.108 μg/m^3), these concentrations are less than 0.04 percent of the levels that cause foliar injury in acute exposure scenarios. By comparison of published toxicity values for NO_2 exposure to long-term (annual averaging time) modeled concentrations, the possibility of plant damage in the Class I area can be examined for chronic exposure situations. For a chronic exposure, the annual estimated NO_2 concentrations due to the project only at the point of maximum impact in the Class I area are 0.003 and 0.02 μg/m^3 when the project is firing natural gas and fuel oil, respectively. These values are less than 0.001 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 national park are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

7.4.3.5 CO

As with PM, information pertaining to the effects of CO on plants is scarce. The primary effect of high CO concentrations 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 μg/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 μg/m^3). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

By comparison of published effect values for CO exposure, the possibility of plant damage in the Class I areas can be determined. The predicted maximum annual concentrations due to the project only in the Class I area are 0.0024 and 0.005 μg/m^3 for natural gas and fuel oil, respectively. These concentrations are <0.000001 percent of the minimum value that caused inhibition in laboratory studies.

7.4.3.6 Summary

In summary, the phytotoxic effects from the proposed plant emissions are minimal. It is important to note that the elements were conservatively modeled with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.4.4 WILDLIFE

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the National AAQS. 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).

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 AAQS. Physiological and behavioral effects have been observed in experimental animals at or below these standards. For impacts on wildlife, the lowest threshold values of SO_2, NO_2, and particulates which 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 effects on wildlife AQRVs from SO_2, NO_2, and particulates are expected. The proposed project's contribution to cumulative impacts is negligible.

7.5 IMPACTS UPON VISIBILITY

7.5.1 INTRODUCTION

A change in visibility is characterized by either a change in the visual range, defined as the greatest distance that a large dark object can be seen, or by a 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 that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where

b_{exts} is the extinction coefficient calculated for the source, and

b_{extb} is the background extinction coefficient

The source extinction coefficient is determined from NO_x, SO_2, and PM_{10} emission's increase from the proposed project. The background extinction coefficient s for each area evaluated are based on existing ambient monitoring data. Based on predicted SO_4, NO_3, and PM_{10} concentrations, the increase in the project's emissions were compared a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

The modeling analysis determined the deciview change at receptors along a circle of 152 km. This represents the minimum distance of the ENP PSD Class I area from the IPS DeSoto power plant site.

7.5.2 ANALYSIS METHODOLOGY

Following the recommendations of the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report, a level II screening analysis was performed using the California Puff (CALPUFF) long-range transport model, along with an enhanced ISC meteorological data record. The CALPUFF postprocessor model CALPOST was used to summarize the maximum concentrations of SO_4, NO_3, and PM_{10} that were predicted with the CALPUFF model.

CALPUFF used in a manner recommended by the IWAQM Phase 2 Summary Report (EPA, 12/98). A summary of the parameter settings that were used in the CALPUFF model is presented in Table E-1 of Appendix E along with the IWAQM Phase 2 recommended parameter settings. The recommended parameter settings are presented in Appendix B of the IWAQM Phase II Summary Report. The CALPUFF model was used in an ISC screening mode with an "enhanced" ISCST3 meteorological data set.

The following CALPUFF settings/values were implemented in the Level II screening analysis:

- Use of six pollutant species of SO_2, SO_4, NO_x, HNO_3, NO_3, and PM_{10};
- Use of MESOPUFF II scheme for chemical transformation with CALPUFF default background concentrations;
- Include both dry and wet deposition and plume depletion;
- Use Agricultural, unirrigated land use; minimum mixing height of 50 m;
- Use transitional plume rise, stack-tip downwash, and partial plume penetration;
- Use puff plume element dispersion, PG/MP coefficients, rural mode, and ISC building downwash scheme;
- Use of partial plume path adjustment terrain effects; and
- Use highest predicted concentrations in 5 years for comparison to the maximum percent change in extinction.

7.5.3 EMISSION INVENTORY

Based on recommendations of the IWAQM Phase II Report, the regional haze analysis considered only the maximum 24-hour increase in emissions due to the two proposed simple-cycle CT's. A summary of the maximum SO_2, NO_x and PM_{10} emission rates for the CT's are presented in Chapter 2. Based on the air modeling analysis, the maximum PSD Class I impacts for the project occurred base load, 35 degrees, and fuel oil firing. Emission rates used for the regional haze reflected this emission scenario.

7.5.4 BUILDING WAKE EFFECTS

The air modeling analysis included the same building structure dimensions to account for the effects of building-induced downwash as was used in the ISCST3 modeling analysis. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and were included in the CALPUFF model.

7.5.5 RECEPTOR LOCATIONS

Receptors were located along a circle that was centered over the proposed project site with radii equal to the minimum distance (i.e., 152 km) from the ENP PSD Class I Area. The circle was comprised of 180 polar receptors, spaced at 2-degree intervals. Because the area's terrain is flat, all receptors were assumed to be at zero elevation.

7.5.6 BACKGROUND VISUAL RANGES AND RELATIVE HUMIDITY FACTORS

The background extinction coefficient was based on data representative of the mean of the top 20-percentile air quality days. For the ENP, a background extinction coefficient of 0.0466 km^{-1} was used, equating to a background visual range of 84 km. This background value was provided by the National Park Service's Air Modeling Branch.

7.5.7 METEOROLOGICAL DATA

A five-year data record was used for years 1987 through 1991. The data set consisting of hourly surface observations from Ft. Myers page field and twice-daily mixing height data from the National Weather Service (NWS) office at Ruskin. The surface and upper data were preprocessed into an ASCII modeling format by EPA 's PCRAMMET meteorological preprocessing program. An anemometer height of 20 ft was used.

Additional meteorological parameters were added to the meteorological data records for use with the CALPUFF model. The addition parameters include friction velocity, Monin-Obukhov length, and surface roughness used for calculating dry deposition; precipitation type code and precipitation rate used for calculating wet deposition, and short-wave solar radiation and relative humidity use for calculating chemical transformation rates. The dry deposition parameters were added to the meteorological data records using the

PCRAMMET model in dry deposition mode. Using the guidance provided in Section 3.1 of the PCRAMMET User's Manual (8/98), the following input values were selected:

1. Surface roughness at both application and measurement sites: 0.15 m
2. Noontime Albedo: 0.18
3. Bowen Ratio: 0.8
4. Anthropogenic Heat flux: 0
5. Minimum Monin-Obukhov Length: 2 m
6. Fraction of Net Radiation Absorbed by Ground: 0.15

Hourly precipitation amounts and relative humidity values were added separately to the meteorological data set. These parameters were obtained from Ft. Myers and were taken instead from West Palm Beach. The West Palm Beach production are considered representative of the proposed site location, because it is at a similar latitude.

Based on the precipitation classification scheme provided in the CALPUFF User's Manual (EPA, 1995), each hour's precipitation code was set to 0 1, 2 or 3. An hour in which no precipitation occurred received a code of 0. If precipitation occurred, the code was set from 1 to 3, depending on the intensity. All precipitation was assumed to be in the form of rain.

7.5.8 CHEMICAL TRANSFORMATION

The air modeling analysis included all chemical transformation processes that occur for the emitted species.

7.5.9 RESULTS

The highest predicted 24-hour species concentrations are summarized in Table 7-5. The maximum predicted SO_4 concentration occurred on Julian day 195, 1991. The maximum predicted NO_3 and PM_{10} concentrations occurred on Julian day 337, 1989 and Julian day 274, 1991, respectively.. The computed average daily relative humidity factors for these days are presented in Table 7-6. The predicted change in visibility for each day is summarized in Table 7-7. The predicted change in visibility is predicted to be 4.44, 7.74, and 4.57 percent, respectively for each critical species day evaluated. The proposed facilities emissions, under fuel oil, were determined to be less than the 5 percent visibility change for 2 of the 3 species worst-case days and exceed a visibility change of 5 percent for only one day. However, the primary fuel is natural gas with distillate oil or backup. For natural gas, the proposed facility's emissions would not adversely impact visibility at the ENP.

Table 7-1. Maximum Predicted Concentrations Due To Project Only at Everglades National Park

Natural Gas Operation

Pollutant	Concentrations[a] (ug/m^3) for Averaging Times				
	Annual	24-Hour	8-Hour	3-Hour	1-Hour
Sulfur Dioxide (SO_2)	0.0003	0.009	ND	0.04	ND
Nitrogen Dioxide (NO_2)	0.003	ND	0.321	ND	ND
Particulates (PM_{10})	0.0007	0.013	0.06	ND	ND
Carbon Monoxide (CO)	0.0024	ND	0.213	ND	0.726

Fuel Oil Operation

Pollutant	Concentrations[a] (ug/m^3) for Averaging Times				
	Annual	24-Hour	8-Hour	3-Hour	1-Hour
Sulfur Dioxide (SO_2)	0.005	0.180	ND	0.8	ND
Nitrogen Dioxide (NO_2)	0.02	ND	1.7	ND	ND
Particulates (PM_{10})	0.001	0.04	0.1	ND	ND
Carbon Monoxide (CO)	0.005	ND	0.41	ND	1.368

[a] From the ISCST3 model and 5 years of hourly meteorlogical data from Ft. Myers/Tampa, 1987-91.

ND = Not determined.

Table 7-2. SO_2 Effects Levels for Various Plant Species

Plant Species	Observed Effect Level (μg/m³)	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 1-Hour	SO_2 Concentration 3-Hour	Plants
Sensitive	1,310 - 2,620 µg/m³ (0.5 - 1.0 ppm)	790 - 1,570 µg/m³ (0.3 - 0.6 ppm)	Ragweeds Legumes Blackberry Southern pines Red and black oaks White ash Sumacs
Intermediate	2,620 - 5,240 µg/m³ (1.0 - 2.0 ppm)	1,570 - 2,100 µg/m³ (0.6 - 0.8 ppm)	Maples Locust Sweetgum Cherry Elms Tuliptree Many crop and garden species
Resistant	>5,240 µg/m³ (>2.0 ppm)	>2,100 µg/m³ (>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[1]	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[2,3]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[1]	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: [1]Newman and Schreiber, 1988.
[2]Gardner and Graham, 1976.
[3]Trzeciak et al., 1977.

Table 7-5. Highest Predicted Species 24-Hour Concentrations and Days

Species Predicted	Year	Concentration[a] (ug/m^3)	Julian Day
SO_4	1987	0.053851	226
	1988	0.038181	134
	1989	0.074058	267
	1990	0.04806	236
	1991	**0.096324**	**195**
NO_3	1987	0.185491	38
	1988	0.2217	347
	1989	**0.24355**	**337**
	1990	0.20235	340
	1991	0.16916	349
PM_{10}	1987	0.032341	360
	1988	0.032877	353
	1989	0.038633	337
	1990	0.037245	340
	1991	**0.045349**	**274**
Additional Concentrations for Worst-Days			
SO_4	1991	0.039082	274
NO_3	1991	0.1092	274
SO_4	1989	0.02759	337
PM	1989	0.038633	337
NO_3	1991	0.06461	195
PM_{10}	1991	0.040461	195

a. Predicted with CALPUFF model and ISCST3 meteorological data from Fort Myers /Tampa for 1987-1991

Note: Values in bold indicated selected species values and worst days

Table 7-6. Computed Daily Average RH Factors for Predicted Worst Days

Hour	December 3, 1989		July 14, 1991		October 1, 1991	
Ending	RH(%)	f(RH)	RH(%)	f(RH)	RH(%)	f(RH)
0	73	2.1	97	15.1	82	3.0
1	73	2.1	97	15.1	82	3.0
2	72	2.0	97	15.1	85	3.4
3	81	2.8	97	15.1	87	3.8
4	87	3.8	97	15.1	87	3.8
5	90	4.7	97	15.1	87	3.8
6	93	7.0	94	8.4	87	3.8
7	84	3.2	82	3.0	85	3.4
8	60	1.4	77	2.4	82	3.0
9	40	1.1	70	1.9	74	2.1
10	30	1.0	61	1.5	69	1.9
11	36	1.0	59	1.4	70	1.9
12	40	1.1	57	1.3	67	1.7
13	22	1.0	63	1.5	70	1.9
14	28	1.0	63	1.5	72	2.0
15	19	1.0	61	1.5	74	2.1
16	22	1.0	63	1.5	79	2.6
17	27	1.0	57	1.3	85	3.4
18	39	1.1	67	1.7	88	4.0
19	37	1.1	70	1.9	85	3.4
20	45	1.2	74	2.1	88	4.0
21	57	1.3	82	3.0	91	5.3
22	49	1.2	88	4.0	94	8.4
23	44	1.2	88	4.0	94	8.4
Average		1.89		5.60		3.50

a. Hourly relative humidity data from Fort Myers, Fl

Table 7-7. Regional Haze Screening Analysis Results, IPS Arcadia - 3 Simple-Cycle CTs, Oil Firing

Item	Units	Species Worst-Days		
		12/3/89 (337)	7/14/91 (195)	10/1/91 (274)
Maximum Predicted Concentrations	ug/m^3			
PM_{10}		0.038633	0.040461	0.045349
SO_4		0.027590	0.096324	0.039082
NO_3		0.243550	0.06461	0.1092
Computed Concentrations	ug/m^3			
$(NH_4)_2SO_4$		0.037936	0.132446	0.053738
NH_4NO_3		0.3142	0.0833	0.1409
Average Relative Humidity Factor(a)		1.89	5.6	3.5
Background Visual Range(b), Vr		84	84	84
Background Extinction Coeff.(bext)	km^{-1}	0.0466	0.0466	0.0466
Source Extinction Coeff (bexts)	km^{-1}			
$(NH_4)_2SO_4$		0.000215	0.002225	0.000564
NH_4NO_3		0.001781	0.001400	0.001479
PM_{10}		0.000116	0.000121	0.000136
Total bexts	km^{-1}	0.002112	0.003747	0.002179
Deciview Change		0.444	0.774	0.457
Percent Change (%)		4.44	7.74	4.57
Allowable Criteria (%)		5.0	5.0	5.0

a. Computed from Ft. Myers RH data
b. Provided by National Park Service

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APPENDIX A

EXPECTED PERFORMANCE AND EMISSION INFORMATION ON GE FRAME 7FA 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 IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Combustion Turbine Performance			
Net power output (MW)	179.2	172.2	156.6
Net heat rate (Btu/kWh, LHV)	9,319	9,361	9,591
(Btu/kWh, HHV)	10,344	10,391	10,646
Heat Input (MMBtu/hr, LHV)	1,670	1,612	1,502
(MMBtu/hr, HHV)	1,854	1,789	1,667
Fuel heating value (Btu/lb, LHV)	20,751	20,751	20,751
(Btu/lb, HHV)	23,006	23,006	23,006
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin of 10%	4,063,400	3,919,300	3,672,900
- provided	3,694,000	3,563,000	3,339,000
Temperature (°F)	1,097	1,113	1,135
Moisture (% Vol.)	7.9	8.6	10.3
Oxygen (% Vol.)	12.60	12.50	12.20
Molecular Weight	28.44	28.34	28.16
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)	1,670	1,612	1,502
Heat content (Btu/lb, LHV)	20,751	20,751	20,751
Fuel usage (lb/hr)- calculated	80,478	77,683	72,382
CT Stack			
Stack height (ft)	60	60	60
Diameter (ft)	22	22	22
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)	4,063,400	3,919,300	3,672,900
Temperature (°F)	1,097	1,113	1,135
Molecular weight	28.44	28.34	28.16
Volume flow (acfm)- calculated	2,706,395	2,645,986	2,530,918
(ft3/s)- calculated	45,107	44,100	42,182
Velocity (ft/sec)	118.7	116.0	111.0

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, 1998.

Table A-2. Maximum Emissions for Criteria Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	3,390	3,390	3,390
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer			
Basis (excludes H_2SO_4), lb/hr	10	10	10
Emission rate (lb/hr)- provided	10.0	10.0	10.0
(TPY)	17.0	17.0	17.0
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448
Fuel use (cf/hr)	1,797,031	1,734,619	1,616,252
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)	5.1	5.0	4.6
(TPY)	8.70	8.40	7.83
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2	9	9	9
Moisture (%)	7.9	8.6	10.3
Oxygen (%)	12.6	12.5	12.2
Turbine Flow (acfm)	2,706,395	2,645,986	2,530,918
Turbine Exhaust Temperature (°F)	1,097	1,113	1,135
Emission rate (lb/hr)	66.7	64.1	59.9
(TPY)	113.0	108.6	101.6
Carbon Monoxide (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	12	12	12
Moisture (%)	7.9	8.6	10.3
Turbine Flow (acfm)	2,706,395	2,645,986	2,530,918
Turbine Exhaust Temperature (°F)	1,097	1,113	1,135
Emission rate (lb/hr)	44.2	42.5	39.3
(TPY)	75.0	72.0	66.6
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft2 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, ppmvd	1.4	1.4	1.4
Moisture (%)	7.9	8.6	10.3
Turbine Flow (acfm)	2,706,395	2,645,986	2,530,918
Turbine Exhaust Temperature (°F)	1,097	1,113	1,135
Emission rate (lb/hr)	2.95	2.83	2.62
(TPY)	5.0	4.8	4.4
Lead (lb/hr)= NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA
(TPY)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 1998; Golder Associates, 1998; EPA, 1996

Table A-3. Maximum Emissions for Other Regulated PSD Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	3,390	3,390	3,390
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	1.20E-06	1.20E-06	0.00E+00
Heat Input Rate (MMBtu/hr)	1.85E+03	1.79E+03	1.67E+03
Emission Rate (lb/hr)	2.22E-09	2.15E-09	0.00E+00
(TPY)	3.77E-09	3.64E-09	0.00E+00
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	7.48E-04	7.48E-04	7.48E-04
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	1.39E-06	1.34E-06	1.25E-06
(TPY)	2.35E-06	2.27E-06	2.11E-06
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)			
Fuel Usage (cf/hr)	1,797,031	1,734,619	1,616,252
Sulfur (lb/hr)	2.57	2.48	2.31
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (c)	10	10	10
Emission Rate (lb/hr)	0.79	0.76	0.71
(TPY)	1.33	1.29	1.20

Sources: (a) Golder Associates, 1998; (b) EPA, 1981; (c) Assumed.

Note: No Emission Factors for Hydrogen chloride (HCl) from natural gas firing.

Table A-4. Maximum Emissions for Hazardous Air Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	3,390	3,390	3,390
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0.8	0.8	0.8
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	1.48E-03	1.43E-03	1.33E-03
(TPY)	2.51E-03	2.43E-03	2.26E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	34	34	34
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	6.30E-02	6.08E-02	5.67E-02
(TPY)	1.07E-01	1.03E-01	9.61E-02
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1.85E+03	1.79E+03	1.67E+03
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	10	10	10
Heat Input Rate (MMBtu/hr)	1,854	1,789	1,667
Emission Rate (lb/hr)	1.85E-02	1.79E-02	1.67E-02
(TPY)	3.14E-02	3.03E-02	2.83E-02

Sources: (a) Golder Associates, 1998; (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-5. Design Information and Stack Parameters for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Combustion Turbine Performance			
Net power output (MW)	134.2	126.4	111.1
Net heat rate (Btu/kWh, LHV)	10,261	10,396	10,882
(Btu/kWh, HHV)	11,045	11,289	11,765
Heat Input (MMBtu/hr, LHV)	1,377	1,314	1,209
(MMBtu/hr, HHV)	1,482	1,427	1,307
Fuel heating value (Btu/lb, LHV)	20,751	20,751	20,751
(Btu/lb, HHV)	23,006	23,006	23,006
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin of 10%	3,285,700	3,190,000	3,039,300
- provided	2,987,000	2,900,000	2,763,000
Temperature (°F)	1,170	1,179	1,193
Moisture (% Vol.)	8.1	8.4	9.6
Oxygen (% Vol.)	12.50	12.50	12.50
Molecular Weight	28.41	28.38	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)	1,377	1,314	1,209
Heat content (Btu/lb, LHV)	20,751	20,751	20,751
Fuel usage (lb/hr)- calculated	66,358	63,322	58,262
CT Stack			
Stack height (ft)	60	60	60
Diameter (ft)	22	22	22
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)	3,285,700	3,190,000	3,039,300
Temperature (°F)	1,170	1,179	1,193
Molecular weight	28.41	28.38	28.21
Volume flow (acfm)- calculated	2,292,951	2,240,823	2,166,041
(ft3/s)- calculated	38,216	37,347	36,101
Velocity (ft/sec)	100.5	98.2	95.0

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, 1998.

Table A-6. Maximum Emissions for Criteria Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	3,390	3,390	3,390
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer			
Basis (excludes H_2SO_4), lb/hr	10	10	10
Emission rate (lb/hr)- provided	10.0	10.0	10.0
(TPY)	17.0	17.0	17.0
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448
Fuel use (cf/hr)	1,481,744	1,413,951	1,300,964
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)	4.2	4.0	3.7
(TPY)	7.18	6.85	6.30
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2	9	9	9
Moisture (%)	8.1	8.4	9.6
Oxygen (%)	12.5	12.5	12.5
Turbine Flow (acfm)	2,292,951	2,240,823	2,166,041
Turbine Exhaust Temperature (°F)	1,170	1,179	1,193
Emission rate (lb/hr)	54.4	52.4	48.3
(TPY)	92.2	88.8	81.9
Carbon Monoxide (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	12	12	12
Moisture (%)	8.1	8.4	9.6
Turbine Flow (acfm)	2,292,951	2,240,823	2,166,041
Turbine Exhaust Temperature (°F)	1,170	1,179	1,193
Emission rate (lb/hr)	35.7	34.6	32.7
(TPY)	60.5	58.6	55.5
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft2 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, ppmvd	1.4	1.4	1.4
Moisture (%)	8.1	8.4	9.6
Turbine Flow (acfm)	2,292,951	2,240,823	2,166,041
Turbine Exhaust Temperature (°F)	1,170	1,179	1,193
Emission rate (lb/hr)	2.38	2.31	2.18
(TPY)	4.0	3.9	3.7
Lead (lb/hr)= NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA
(TPY)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 1998; Golder Associates, 1998; EPA, 1996

Table A-7. Maximum Emissions for Other Regulated PSD Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	3,390	3,390	3,390
2,3,7,8-TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1.48E+03	1.43E+03	1.31E+03
Emission Rate (lb/hr)	1.78E-09	1.71E-09	1.57E-09
(TPY)	3.01E-09	2.90E-09	2.66E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	7.48E-04	7.48E-04	7.48E-04
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	1.11E-06	1.07E-06	9.78E-07
(TPY)	1.88E-06	1.81E-06	1.66E-06
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)			
Fuel Usage (cf/hr)	1,481,744	1,413,951	1,300,964
Sulfur (lb/hr)	2.12	2.02	1.86
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (c)	10	10	10
Emission Rate (lb/hr)	0.65	0.62	0.57
(TPY)	1.10	1.05	0.96

Sources: (a) Golder Associates, 1998; (b) EPA, 1981; (c) Assumed.

Table A-8. Maximum Emissions for Hazardous Air Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 75% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	3,390	3,390	3,390
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0.8	0.8	0.8
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	1.19E-03	1.14E-03	1.05E-03
(TPY)	2.01E-03	1.93E-03	1.77E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	34	34	34
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	5.04E-02	4.85E-02	4.44E-02
(TPY)	8.54E-02	8.22E-02	7.53E-02
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1.48E+03	1.43E+03	1.31E+03
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	10	10	10
Heat Input Rate (MMBtu/hr)	1,482	1,427	1,307
Emission Rate (lb/hr)	1.48E-02	1.43E-02	1.31E-02
(TPY)	2.51E-02	2.42E-02	2.22E-02

Sources: (a) Golder Associates, 1998; (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-9. Design Information and Stack Parameters for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Combustion Turbine Performance			
Net power output (MW)	90.76	85.55	74.6
Net heat rate (Btu/kWh, LHV)	12,054	12,086	12,842
(Btu/kWh, HHV)	13,380	13,416	14,254
Heat Input (MMBtu/hr, LHV)	1,094	1,034	958
(MMBtu/hr, HHV)	1,214	1,148	1,063
Fuel heating value (Btu/lb, LHV)	20,751	20,751	20,751
(Btu/lb, HHV)	23,006	23,006	23,006
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin of 10%	2,754,400	2,654,300	2,570,700
- provided	2,504,000	2,413,000	2,337,000
Temperature (°F)	1,171	1,186	1,200
Moisture (% Vol.)	7.7	8	9.1
Oxygen (% Vol.)	12.90	13.00	13.00
Molecular Weight	28.44	28.41	28.26
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)	1,094	1,034	958
Heat content (Btu/lb, LHV)	20,751	20,751	20,751
Fuel usage (lb/hr)- calculated	52,720	49,829	46,166
CT Stack			
Stack height (ft)	60	60	60
Diameter (ft)	22	22	22
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)	2,754,400	2,654,300	2,570,700
Temperature (°F)	1,171	1,186	1,200
Molecular weight	28.44	28.41	28.26
Volume flow (acfm)- calculated	1,921,470	1,870,642	1,836,829
(ft3/s)- calculated	32,024	31,177	30,614
Velocity (ft/sec)	84.2	82.0	80.5

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, 1998.

Table A-10. Maximum Emissions for Criteria Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	3,390	3,390	3,390
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer			
Basis (excludes H_2SO_4), lb/hr	10	10	10
Emission rate (lb/hr)- provided	10.0	10.0	10.0
(TPY)	17.0	17.0	17.0
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448
Fuel use (cf/hr)	1,177,217	1,112,653	1,030,872
Sulfur content (grains/ 100 cf)	1	1	1
lb SO_2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)	3.4	3.2	2.9
(TPY)	5.70	5.39	4.99
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2	9	9	9
Moisture (%)	7.7	8	9.1
Oxygen (%)	12.9	13	13
Turbine Flow (acfm)	1,921,470	1,870,642	1,836,829
Turbine Exhaust Temperature (°F)	1,171	1,186	1,200
Emission rate (lb/hr)	43.4	40.8	38.3
(TPY)	73.6	69.2	64.9
Carbon Monoxide (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	12	12	12
Moisture (%)	7.7	8	9.1
Turbine Flow (acfm)	1,921,470	1,870,642	1,836,829
Turbine Exhaust Temperature (°F)	1,171	1,186	1,200
Emission rate (lb/hr)	30.0	28.9	27.8
(TPY)	50.9	49.0	47.1
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft2 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, ppmvd	1.4	1.4	1.4
Moisture (%)	7.7	8	9.1
Turbine Flow (acfm)	1,921,470	1,870,642	1,836,829
Turbine Exhaust Temperature (°F)	1,171	1,186	1,200
Emission rate (lb/hr)	2.00	1.93	1.85
(TPY)	3.4	3.3	3.1
Lead (lb/hr)= NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA
(TPY)	NA	NA	NA

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 1998; Golder Associates, 1998; EPA, 1996

Table A-11. Maximum Emissions for Other Regulated PSD Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	3,390	3,390	3,390
2,3,7,8-TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1.21E+03	1.15E+03	1.06E+03
Emission Rate (lb/hr)	1.46E-09	1.38E-09	1.28E-09
(TPY)	2.47E-09	2.33E-09	2.16E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	7.48E-04	7.48E-04	7.48E-04
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	9.08E-07	8.59E-07	7.95E-07
(TPY)	1.54E-06	1.46E-06	1.35E-06
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)			
Fuel Usage (cf/hr)	1,177,217	1,112,653	1,030,872
Sulfur (lb/hr)	1.68	1.59	1.47
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (c)	10	10	10
Emission Rate (lb/hr)	0.52	0.49	0.45
(TPY)	0.87	0.83	0.76

Sources: (a) Golder Associates, 1998; (b) EPA, 1981; (c) Assumed.

Table A-12. Maximum Emissions for Hazardous Air Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, 50% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	3,390	3,390	3,390
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0.8	0.8	0.8
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	9.71E-04	9.18E-04	8.51E-04
(TPY)	1.65E-03	1.56E-03	1.44E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	34	34	34
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	4.13E-02	3.90E-02	3.62E-02
(TPY)	7.00E-02	6.61E-02	6.13E-02
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1.21E+03	1.15E+03	1.06E+03
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0	0	0
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	10	10	10
Heat Input Rate (MMBtu/hr)	1,214	1,148	1,063
Emission Rate (lb/hr)	1.21E-02	1.15E-02	1.06E-02
(TPY)	2.06E-02	1.95E-02	1.80E-02

Sources: (a) Golder Associates, 1998; (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-13. Design Information and Stack Parameters for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Combustion Turbine Performance			
Net power output (MW)	183.9	181.9	171.2
Net heat rate (Btu/kWh, LHV)	10,103	9,929	9,988
(Btu/kWh, HHV)	10,710	10,524	10,588
Heat Input (MMBtu/hr, LHV)	1,858	1,806	1,710
(MMBtu/hr, HHV)	1,969	1,914	1,813
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin of 10%	4,230,600	4,081,000	3,825,800
- provided	3,846,000	3,710,000	3,478,000
Temperature (°F)	1,076	1,094	1,121
Moisture (% Vol.)	11	11.7	13.3
Oxygen (% Vol.)	11.20	11.04	10.60
Molecular Weight	28.33	28.25	28.06
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)	1,858	1,806	1,710
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	101,530	98,689	93,443
CT Stack			
Stack height (ft)	60	60	60
Diameter (ft)	22	22	22
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)	4,230,600	4,081,000	3,825,800
Temperature (°F)	1,076	1,094	1,121
Molecular weight	28.33	28.25	28.06
Volume flow (acfm)- calculated	2,790,601	2,731,215	2,622,427
(ft3/s)- calculated	46,510	45,520	43,707
Velocity (ft/sec)	122.4	119.7	115.0

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, 1999; Golder Associates, 1999

Table A-14. Maximum Emissions for Criteria Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer			
Basis (excludes H_2SO_4), lb/hr	17	17	17
Emission rate (lb/hr)- provided	17.0	17.0	17.0
(TPY)	8.5	8.5	8.5
Sulfur Dioxide (lb/hr) = Natural gas (lb/hr) x sulfur content (%/100) x (lb SO_2 /lb S)			
Fuel Sulfur Content	0.05%	0.05%	0.05%
Fuel use (lb/hr)	101,530	98,689	93,443
lb SO_2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)	101.5	98.7	93.4
(TPY)	50.77	49.34	46.72
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2	42	42	42
Moisture (%)	11	11.7	13.3
Oxygen (%)	11.2	11.04	10.6
Turbine Flow (acfm)	2,790,601	2,731,215	2,622,427
Turbine Exhaust Temperature (°F)	1,076	1,094	1,121
Emission rate (lb/hr)	362.0	350.8	335.8
(TPY)	181.0	175.4	167.9
Carbon Monoxide (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	20	20	20
Moisture (%)	11	11.7	13.3
Turbine Flow (acfm)	2,790,601	2,731,215	2,622,427
Turbine Exhaust Temperature (°F)	1,076	1,094	1,121
Emission rate (lb/hr)	74.4	71.4	66.2
(TPY)	37.2	35.7	33.1
VOCs (lb/hr) = VOC(ppmvw) x 2116.8 lb/ft2 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	7	7	7
Turbine Flow (acfm)	2,790,601	2,731,215	2,622,427
Turbine Exhaust Temperature (°F)	1,076	1,094	1,121
Emission rate (lb/hr)	16.73	16.18	15.27
(TPY)	8.4	8.1	7.6
Lead (lb/hr)= NA			
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8
Emission rate (lb/hr)	0.0213	0.0207	0.0196
(TPY)	0.0106	0.0103	0.0098

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 1998; Golder Associates, 1998; EPA, 1998 (AP-42 draft revisions)

Table A-15. Maximum Emissions for Other Regulated PSD Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	3.38E-04	3.38E-04	3.38E-04
Heat Input Rate (MMBtu/hr)	1.97E+03	1.91E+03	1.81E+03
Emission Rate (lb/hr)	6.66E-07	6.47E-07	6.13E-07
(TPY)	3.33E-07	3.24E-07	3.06E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	6.52E-04	6.34E-04	6.00E-04
(TPY)	3.26E-04	3.17E-04	3.00E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	6.41E-02	6.23E-02	5.90E-02
(TPY)	3.20E-02	3.11E-02	2.95E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (c) , lb/10^{12} Btu	2.12E+02	2.12E+02	2.12E+02
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	4.18E-01	4.06E-01	3.84E-01
(TPY)	2.09E-01	2.03E-01	1.92E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	1.23E-03	1.20E-03	1.13E-03
(TPY)	6.16E-04	5.99E-04	5.67E-04
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)			
Fuel Usage (cf/hr)	101,530	98,689	93,443
Sulfur (lb/hr)	50.77	49.34	46.72
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (d)	10	10	10
Emission Rate (lb/hr)	15.55	15.11	14.31
(TPY)	7.77	7.56	7.15

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA, 1981; (c) 4 ppm assumed based on ASTM D2880
(d) assumed based on combustion effects.

Table A-16. Maximum Emissions for Hazardous Air Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, Base Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	1.56E-02	1.51E-02	1.43E-02
(TPY)	7.79E-03	7.57E-03	7.17E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	2.17E-03	2.11E-03	1.99E-03
(TPY)	1.08E-03	1.05E-03	9.97E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	6.38E-03	6.20E-03	5.87E-03
(TPY)	3.19E-03	3.10E-03	2.94E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	1.33E-02	1.29E-02	1.23E-02
(TPY)	6.66E-03	6.47E-03	6.13E-03
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	2	2	2
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	3.94E-03	3.83E-03	3.63E-03
(TPY)	1.97E-03	1.91E-03	1.81E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	1.97E+03	1.91E+03	1.81E+03
Emission Rate (lb/hr)	7.29E-02	7.08E-02	6.71E-02
(TPY)	3.64E-02	3.54E-02	3.35E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	8.51E-01	8.27E-01	7.83E-01
(TPY)	4.25E-01	4.14E-01	3.92E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	1.70E-01	1.65E-01	1.56E-01
(TPY)	8.50E-02	8.26E-02	7.82E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	0.590844	0.574308	0.54378
(TPY)	0.295422	0.287154	0.27189
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	4.53E-02	4.40E-02	4.17E-02
(TPY)	2.26E-02	2.20E-02	2.08E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	1,969	1,914	1,813
Emission Rate (lb/hr)	4.67E-01	4.54E-01	4.30E-01
(TPY)	2.33E-01	2.27E-01	2.15E-01

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-17. Design Information and Stack Parameters for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Combustion Turbine Performance			
Net power output (MW)	136.6	132.3	118.5
Net heat rate (Btu/kWh, LHV)	11,069	11,073	11,553
(Btu/kWh, HHV)	11,733	11,738	12,246
Heat Input (MMBtu/hr, LHV)	1,512	1,465	1,369
(MMBtu/hr, HHV)	1,603	1,553	1,451
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin of 10%	3,287,900	3,225,200	3,106,400
- provided	2,989,000	2,932,000	2,824,000
Temperature (°F)	1,170	1,176	1,186
Moisture (% Vol.)	11.5	11.8	12.9
Oxygen (% Vol.)	10.70	10.80	10.80
Molecular Weight	28.29	28.26	28.12
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)	1,512	1,465	1,369
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	82,623	80,055	74,809
CT Stack			
Stack height (ft)	60	60	60
Diameter (ft)	22	22	22
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)	3,287,900	3,225,200	3,106,400
Temperature (°F)	1,170	1,176	1,186
Molecular weight	28.29	28.26	28.12
Volume flow (acfm)- calculated	2,304,584	2,271,141	2,212,060
(ft3/s)- calculated	38,410	37,852	36,868
Velocity (ft/sec)	101.0	99.6	97.0

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, 1999; Golder Associates, 1999

Table A-18. Maximum Emissions for Criteria Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer			
Basis (excludes H_2SO_4), lb/hr	17	17	17
Emission rate (lb/hr)- provided	17.0	17.0	17.0
(TPY)	8.5	8.5	8.5
Sulfur Dioxide (lb/hr) = Natural gas (lb/hr) x sulfur content (%/100) x (lb SO_2 /lb S)			
Fuel Sulfur Content	0.05%	0.05%	0.05%
Fuel use (lb/hr)	82,623	80,055	74,809
lb SO_2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)	82.6	80.1	74.8
(TPY)	41.31	40.03	37.40
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2	42	42	42
Moisture (%)	11.5	11.8	12.9
Oxygen (%)	10.7	10.8	10.8
Turbine Flow (acfm)	2,304,584	2,271,141	2,212,060
Turbine Exhaust Temperature (°F)	1,170	1,176	1,186
Emission rate (lb/hr)	296.7	285.3	267.8
(TPY)	148.4	142.6	133.9
Carbon Monoxide (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	20	20	20
Moisture (%)	11.5	11.8	12.9
Turbine Flow (acfm)	2,304,584	2,271,141	2,212,060
Turbine Exhaust Temperature (°F)	1,170	1,176	1,186
Emission rate (lb/hr)	57.6	56.4	53.9
(TPY)	28.8	28.2	26.9
VOCs (lb/hr) = VOC(ppmvw) x 2116.8 lb/ft2 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	7	7	7
Turbine Flow (acfm)	2,304,584	2,271,141	2,212,060
Turbine Exhaust Temperature (°F)	1,170	1,176	1,186
Emission rate (lb/hr)	13.02	12.78	12.37
(TPY)	6.5	6.4	6.2
Lead (lb/hr)= NA			
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8
Emission rate (lb/hr)	0.0173	0.0168	0.0157
(TPY)	0.0087	0.0084	0.0078

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 1998; Golder Associates, 1998; EPA, 1996 (AP-42 draft revisions)

Table A-19. Maximum Emissions for Other Regulated PSD Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1.60E+03	1.55E+03	1.45E+03
Emission Rate (lb/hr)	6.09E-07	5.90E-07	5.51E-07
(TPY)	3.05E-07	2.95E-07	2.76E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	5.31E-04	5.14E-04	4.80E-04
(TPY)	2.65E-04	2.57E-04	2.40E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	5.22E-02	5.05E-02	4.72E-02
(TPY)	2.61E-02	2.53E-02	2.36E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (c) , lb/10^{12} Btu	2.12E+02	2.12E+02	2.12E+02
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	3.40E-01	3.29E-01	3.08E-01
(TPY)	1.70E-01	1.65E-01	1.54E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	1.00E-03	9.72E-04	9.08E-04
(TPY)	5.02E-04	4.86E-04	4.54E-04
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)			
Fuel Usage (cf/hr)	82,623	80,055	74,809
Sulfur (lb/hr)	41.31	40.03	37.40
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (d)	10	10	10
Emission Rate (lb/hr)	12.65	12.26	11.46
(TPY)	6.33	6.13	5.73

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA, 1981; (c) 4 ppm assumed based on ASTM D2880
(d) assumed based on combustion effects.

Table A-20. Maximum Emissions for Hazardous Air Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 75% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	1.27E-02	1.23E-02	1.15E-02
(TPY)	6.34E-03	6.14E-03	5.74E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	1.76E-03	1.71E-03	1.60E-03
(TPY)	8.81E-04	8.54E-04	7.98E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	5.19E-03	5.03E-03	4.70E-03
(TPY)	2.60E-03	2.52E-03	2.35E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	1.08E-02	1.05E-02	9.81E-03
(TPY)	5.42E-03	5.25E-03	4.90E-03
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	2	2	2
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	3.21E-03	3.11E-03	2.90E-03
(TPY)	1.60E-03	1.55E-03	1.45E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	1.60E+03	1.55E+03	1.45E+03
Emission Rate (lb/hr)	5.93E-02	5.75E-02	5.37E-02
(TPY)	2.97E-02	2.87E-02	2.68E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	6.92E-01	6.71E-01	6.27E-01
(TPY)	3.46E-01	3.35E-01	3.13E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	1.38E-01	1.34E-01	1.25E-01
(TPY)	6.92E-02	6.70E-02	6.26E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	0.480816	0.46587	0.435342
(TPY)	0.240408	0.232935	0.217671
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	3.69E-02	3.57E-02	3.34E-02
(TPY)	1.84E-02	1.79E-02	1.67E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	1,603	1,553	1,451
Emission Rate (lb/hr)	3.80E-01	3.68E-01	3.44E-01
(TPY)	1.90E-01	1.84E-01	1.72E-01

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA,1996 (AP-42,Table 3.1-4)

Table A-21. Design Information and Stack Parameters for IPS - DeSoto Repowering Project
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Combustion Turbine Performance			
Net power output (MW)	90.2	87.3	77.6
Net heat rate (Btu/kWh, LHV)	13,304	13,162	13,892
(Btu/kWh, HHV)	14,102	13,951	14,725
Heat Input (MMBtu/hr, LHV)	1,200	1,149	1,078
(MMBtu/hr, HHV)	1,272	1,218	1,143
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- with margin of 10%	2,737,900	2,655,400	2,586,100
- provided	2,489,000	2,414,000	2,351,000
Temperature (°F)	1,200	1,200	1,200
Moisture (% Vol.)	11.2	11.6	12.7
Oxygen (% Vol.)	11.10	11.20	11.30
Molecular Weight	28.29	28.24	28.10
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)	1,200	1,149	1,078
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	65,574	62,787	58,907
CT Stack			
Stack height (ft)	60	60	60
Diameter (ft)	22	22	22
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)	2,737,900	2,655,400	2,586,100
Temperature (°F)	1,200	1,200	1,200
Molecular weight	28.29	28.24	28.10
Volume flow (acfm)- calculated	1,954,205	1,898,809	1,858,599
(ft3/s)- calculated	32,570	31,647	30,977
Velocity (ft/sec)	85.7	83.3	81.5

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, 1999; Golder Associates, 1999

Table A-22. Maximum Emissions for Criteria Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer			
Basis (excludes H_2SO_4), lb/hr	17	17	17
Emission rate (lb/hr)- provided	17.0	17.0	17.0
(TPY)	8.5	8.5	8.5
Sulfur Dioxide (lb/hr) = Natural gas (lb/hr) x sulfur content (%/100) x (lb SO_2 /lb S)			
Fuel Sulfur Content	0.05%	0.05%	0.05%
Fuel use (lb/hr)	65,574	62,787	58,907
lb SO_2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)	65.6	62.8	58.9
(TPY)	32.79	31.39	29.45
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2	42	42	42
Moisture (%)	11.2	11.6	12.7
Oxygen (%)	11.1	11.2	11.3
Turbine Flow (acfm)	1,954,205	1,898,809	1,858,599
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
Emission rate (lb/hr)	236.4	224.0	209.3
(TPY)	118.2	112.0	104.7
Carbon Monoxide (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	30	30	30
Moisture (%)	11.2	11.6	12.7
Turbine Flow (acfm)	1,954,205	1,898,809	1,858,599
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
Emission rate (lb/hr)	72.2	69.8	67.5
(TPY)	36.1	34.9	33.7
VOCs (lb/hr) = VOC(ppmvw) x 2116.8 lb/ft2 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	7	7	7
Turbine Flow (acfm)	1,954,205	1,898,809	1,858,599
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
Emission rate (lb/hr)	10.84	10.53	10.31
(TPY)	5.4	5.3	5.2
Lead (lb/hr)= NA			
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8
Emission rate (lb/hr)	0.0137	0.0132	0.0123
(TPY)	0.0069	0.0066	0.0062

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 1998; Golder Associates, 1998; EPA, 1996 (AP-42 draft revisions)

Table A-23. Maximum Emissions for Other Regulated PSD Pollutants for IPS - DeSoto GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil, 50% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1.27E+03	1.22E+03	1.14E+03
Emission Rate (lb/hr)	4.83E-07	4.63E-07	4.34E-07
(TPY)	2.42E-07	2.31E-07	2.17E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	4.21E-04	4.03E-04	3.78E-04
(TPY)	2.11E-04	2.02E-04	1.89E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	4.14E-02	3.96E-02	3.72E-02
(TPY)	2.07E-02	1.98E-02	1.86E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (c) , lb/10^{12} Btu	2.12E+02	2.12E+02	2.12E+02
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	2.70E-01	2.58E-01	2.42E-01
(TPY)	1.35E-01	1.29E-01	1.21E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	7.96E-04	7.62E-04	7.15E-04
(TPY)	3.98E-04	3.81E-04	3.58E-04
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)			
Fuel Usage (cf/hr)	65,574	62,787	58,907
Sulfur (lb/hr)	32.79	31.39	29.45
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (d)	10	10	10
Emission Rate (lb/hr)	10.04	9.61	9.02
(TPY)	5.02	4.81	4.51

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA, 1981; (c) 4 ppm assumed based on ASTM D2880
(d) assumed based on combustion effects.

Table A-24. Maximum Emissions for Hazardous Air Pollutants for IPS - DeSoto
GE Frame 7FA, Dry Low NOx Combustor, Distillate Oil; 50% Load

Parameter	Ambient Temperature 32 °F	59 °F	95 °F
Hours of Operation	1,000	1,000	1,000
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	1.01E-02	9.63E-03	9.04E-03
(TPY)	5.03E-03	4.82E-03	4.52E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	1.40E-03	1.34E-03	1.26E-03
(TPY)	7.00E-04	6.70E-04	6.28E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	4.12E-03	3.95E-03	3.70E-03
(TPY)	2.06E-03	1.97E-03	1.85E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	8.60E-03	8.23E-03	7.72E-03
(TPY)	4.30E-03	4.12E-03	3.86E-03
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	2	2	2
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	2.54E-03	2.44E-03	2.29E-03
(TPY)	1.27E-03	1.22E-03	1.14E-03
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	37	37	37
Heat Input Rate (MMBtu/hr)	1.27E+03	1.22E+03	1.14E+03
Emission Rate (lb/hr)	4.71E-02	4.51E-02	4.23E-02
(TPY)	2.35E-02	2.25E-02	2.11E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	432	432	432
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	5.50E-01	5.26E-01	4.94E-01
(TPY)	2.75E-01	2.63E-01	2.47E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	1.10E-01	1.05E-01	9.86E-02
(TPY)	5.49E-02	5.26E-02	4.93E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (b) , lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	0.3816	0.365382	0.342804
(TPY)	0.1908	0.182691	0.171402
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	23	23	23
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	2.93E-02	2.80E-02	2.63E-02
(TPY)	1.46E-02	1.40E-02	1.31E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis (a) , lb/10^{12} Btu	237	237	237
Heat Input Rate (MMBtu/hr)	1,272	1,218	1,143
Emission Rate (lb/hr)	3.01E-01	2.89E-01	2.71E-01
(TPY)	1.51E-01	1.44E-01	1.35E-01

Sources: (a) EPA, 1998 (AP-42 draft revisions); (b) EPA,1996 (AP-42,Table 3.1-4)

APPENDIX B

BEST AVAILABLE CONTROL TECHNOLOGY FOR THE PROPOSED COMBUSTION TURBINES

B.1 NEW SOURCE PERFORMANCE STANDARDS

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

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of their potential electric output capacity for sale to any utility power distribution system [40 CFR 60.331 (q)]. The requirements for electric utility stationary gas turbines are applicable to the Frame 7F 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.2 BEST AVAILABLE CONTROL TECHNOLOGY

B.2.1 NITROGEN OXIDES

Advanced dry low-NO_x combustion alone has increasingly been approved by regulatory agencies as BACT and is technically feasible for the proposed project. Available information suggests that "hot" SCR with dry low-NO_x combustor technology or with wet injection is also available.

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. 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 selective catalytic reduction (SCR) with wet injection and wet injection alone. When SCR has been employed, wet injection is used initially to reduce NO_x emissions. However, advanced dry low-NO_x technology has only recently been developed and made available for gas turbines. SCR is a post-combustion control, while advanced dry low-NO_x combustors minimize the formation of NO_x in the combustion process.

SCR has been installed or permitted in over 100 projects. The majority of these projects (more than 90 percent) were initially cogeneration facilities with capacities of 50 MW or less. Most of these projects have been in California. Many of these projects have installed SCR have been in the Southern California NO_2 nonattainment area where SCR was required not as BACT but as LAER, a more stringent requirement. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

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

As noted previously, there are distinct regulatory and policy differences between LAER and BACT.

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.

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

There are also projects with SCR located in Vermont, Massachusetts, Connecticut, New Jersey, New York, Rhode Island, and Virginia. A majority of these projects are also cogenerators or independent power producers. The size of these projects ranges from 22 MW to 450 MW, with a majority less than 100 MW in size. While almost all of the facilities have distillate oil as backup fuel, distillate oil generally is restricted by permit to 1,000 hours or less per CT.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to 80 percent of NO_x in the exhaust gas stream. The most common emission limiting standards associated with SCR are approximately 9 ppm for natural gas firing. However, a few facilities have reported emission limits of 3.5 ppm and less.

Wet injection historically (pre-1990's) has been the primary method of reducing NO_x emissions from CTs. 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. More recently, however, CT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 15 ppmvd (corrected to 15 percent O_2) or less when firing natural gas.

Technology Description 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 30 ppm have been demonstrated. However, wet injection is no longer offered for gas firing in "F" Class turbine. 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 Westinghouse, GE, Kraftwork Union, and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. Westinghouse and GE 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

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, since SCR catalysts are contaminated by sulfur-containing fuels . For most fuel-oil-burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. While the operating experience with SCR has not been extensive, certain cost, technical, and environmental considerations have surfaced for units firing both natural gas and oil while using SCR.

Ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required 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.

Zeolite and specially designed high temperature catalysts, which are reported to be capable of withstanding temperature ranges up to 1,100°F, have become available commercially only recently. Their application with SCR primarily has been limited to internal combustion engines. Optimum performance of an SCR system using a zeolite catalyst is reported to range from about 800°F to 900°F. At temperatures of 1,100°F and above, the high-temperature catalyst will be irreparably damaged.

In the 1990s there are four simple cycle combustion turbine projects that have installed SCR with 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 hour of operation and well less the catalyst guarantee. When firing distillate oil, catalyst deactivation occurred after 600 hours. Due to the problems with oil firing, the SCR system for the Cambalache Facility has been removed. This experience suggests that SCR for simple cycle CTs while available from vendors has not been demonstrated as feasible.

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.

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:

$$CO + ½ O_2 \Rightarrow CO_2 \qquad (1)$$

$$NO + ½ O_2 \Rightarrow NO_2 \qquad (2)$$

$$2NO_2 + K_2CO_3 \Rightarrow CO_2 + KNO_2 + KNO_3 \qquad (3)$$

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:

$$CH_4 + \tfrac{1}{2} O_2 + 1.88\, N_2 \rightarrow CO + 2\, H_2 + 1.88\, N_2 \qquad (5)$$

$$CO + 2\, H_2 + H_2O + 1.88\, N2_2 \rightarrow CO_2 + 3\, H_2 + 1.88\, N_2 \qquad (6)$$

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 (SCONO$_x$™) 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 SCONO$_x$™ process is proprietary. SCONO$_x$™ 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.

The SCONO$_x$™ control technology is not considered to be technically feasible because it has not been commercially demonstrated on large CTs. The CTs planned for the project, Westinghouse 501 F units, each have a nominal generating capacity of 170 MW which are approximately six 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, and the relatively brief (approximately 18 months) operating history of the technology.

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 501F CT is about 1,000°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

Thermal $DeNO_x$

Thermal $DeNO_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal $DeNO_x$ requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream 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 a 501 F 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 technical evaluation of post-combustion gas controls that include NO_xOUT, Thermal DeNO_x, NSCR, and SCONO™ indicate that these processes have not been applied to simple-cycle turbines and are technically infeasible for the project because of process constraints (e.g., temperature). While high-temperature SCR is feasible, it has not been demonstrated on simple-cycle "F" class turbines in peaking service. Wet injection cannot achieve emission rates lower than 25 ppm when firing natural gas in an "F" Class machine and is not offered by the preferred vendor.

For the BACT analysis, dry low-NO_x combustion technology is technically feasible when firing natural gas and SCR in combination with combustion controls is a potentially feasible alternative that can achieve a maximum degree of emission reduction. The advanced dry low-NO_x combustor alone can achieve 9 ppm (corrected) and the SCR with dry low-NO_x combustor is capable of achieving a NO_x emission level of 3.6 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions).

Below is a summary of the technical demonstration and feasibility for the proposed project.

Technology	Simple Cycle
Dry Low-NO_x Combustors	Demonstrated and Feasible – Gas Firing
Wet Injection	Not Feasible/Available – Gas Firing
Wet Injection	Feasible/Available – Oil Firing
Selective Catalytic Reduction	Not Demonstrated on "F" Class turbines in peaking service
Thermal De NO_x	Not Feasible
NO_x Out	Not Feasible
SCO NO_x	Not Feasible
NSCR	Not Feasible

SCR Cost Estimates

Tables B-3 and B-4 present the total capital and annualized cost for SCR applied to simple cycle operation, respectively. The costs were developed using EPA Cost Control Manual (EPA, 1990 & 1993). Vendor based estimates were used for the SCR system. Standard EPA recommended cost factors were used. A capital recovery period of 15 years was used for the capital costs and 3 years for the reoccurring capital costs (i.e., catalyst). SCR system in simple-cycle operation would be subjected to temperatures exceeding 1,000°F where considerable wear can take place resulting in lower life of equipment. Capital recovery periods in this case may be much lower.

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-5 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines. Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design. For the CTs being evaluated, CO emissions will not exceed 12 ppmvd, corrected to 15 percent O_2, dry conditions when firing natural gas under full load conditions.

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

Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required.

For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing oxidation catalyst applications primarily have been limited to smaller cogeneration facilities burning natural gas. Oxidation catalysts have not been used on fuel-oil-fired CTs or combined cycle facilities. The use of sulfur-containing fuels in an oxidation catalyst system would result in an increase of SO_3 emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

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

Oxidation Catalyst Costs

Tables B-6 and B-7 present the capital and annualized cost for an oxidation catalyst applied to simple cycle operation. The maximum CO impacts are less than 0.1 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 Best Available Control Technology (BACT) Determinations for Nitrogen Oxide (NOx) Emissions

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	NOx Emission Limit	Control Method	Efficiency (%	Type
SOUTHERN NATURAL GAS	AL	Mar-98	2-9160 HP GE MODEL MS3002G NATURAL GAS TURBINES	9,160 HP	53 LB/HR		0	BACT-PSD
SOUTHERN NATURAL GAS	AL	Mar-98	9160 HP GE MODEL MS3002G NATURAL GAS FIRED TURBINE	9,160 HP	53 LB/HR		0	BACT-PSD
ALABAMA POWER COMPANY	AL	Dec-97	COMBUSTION TURBINE W/ DUCT BURNER (COMBINED CYCL	100 MW	15 PPM	DRY LOW NOX BURNERS	0	BACT-PSD
BUCKNELL UNIVERSITY	PA	Nov-97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5.0 MW	25 PPMV@15%O2	SOLONOX BURNER: LOW NOX BURNER	0	BACT/OTHER
NORTHERN CALIFORNIA POWER AGENCY	CA	Oct-97	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	25 PPMVD @ 15% O2	DRY LOW NOX BURNERS	0	LAER
LORDSBURG L.P.	NM	Jun-97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	74.4 LBS/HR	DRY LOW-NOX TECHNOLOGY WHICH ADOPTS STAGED OR SCHEDULED COMBUSTION.	80	BACT-PSD
SOUTHERN CALIFORNIA GAS COMPANY	CA	May-97	VARIABLE LOAD NATURAL GAS FIRED TURBINE COMPRESSOR	50 MMBTU/HR	25 PPMVD @ 15% O2	DRY LOW NOX COMBUSTOR	0	LAER
MEAD COATED BOARD, INC.	AL	Mar-97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	25 PPMVD@ 15% O2 (GAS)	FUEL OIL SULFUR CONTENT <=0.05% BY WEIGHT, DRY LOW NOX COMBUSTOR DESIGN FIRING GAS AND DRY LOW NOX COMBUSTOR WITH WATER INJECTION FIRING OIL	0	BACT-PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	LA	Mar-97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	9 PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND	0	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	Feb-97	COMBUSTION TURBINE, NATURAL GAS	100 MW	0 SEE FACILITY NOTES	DRY LOW NOX COMBUSTION	0	BACT-PSD
CALRESOURCES LLC	CA	Jan-97	SOLAR MODEL 1100 SATURN GAS TURBINE	14 MMBTU/HR	69 PPMVD @15% O2	NO CONTROL	0	LAER
TEMPO PLASTICS	CA	Dec-96	GAS TURBINE COGENERATION UNIT	0.0	0.109 LB/MMBTU	LOW-NOX COMBUSTOR	0	LAER
SOUTHERN NATURAL GAS COMPANY	MS	Dec-96	TURBINE, NATURAL GAS-FIRED	9,160 HORSEPOWER	110 PPMV @ 15% O2, DRY	PROPER TURBINE DESIGN AND OPERATION	0	BACT-PSD
SOUTHERN NATURAL GAS COMPANY-SELMA COMPRESSOR STAT	AL	Dec-96	9160 HP GE MS3002G NATURAL GAS FIRED TURBINE	0.0	53 LB/HR		0	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	Nov-96	COMBUSTION TURBINE, NATURAL GAS	100 MW	15 PPM; SEE FAC. NOTES	DRY LOW NOX COMBUSTION	0	BACT-PSD
ECOELECTRICA, L.P.	PR	Oct-96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	68 LB/HR (GAS)	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR).	72	BACT-PSD
ECOELECTRICA, L.P.	PR	Oct-96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	73 LB/HR (OIL)	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR).	72	BACT-PSD
BLUE MOUNTAIN POWER, LP	PA	Jul-96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	4 PPM @ 15% O2	DRY LNB WITH SCR WATER INJECTION IN PLACE WHEN FIRING OIL. OIL FIRING LIMITS SET TO 9.4 PPM @15% O2	84	LAER
CITY OF ST.PAUL POWER PLANT	AK	Jun-96	INTERNAL COMBUSTION	3.4 MW	427 TPY	AFTERCOOLERS	0	BACT-PSD
CITY OF UNALASKA	AK	Jun-96	INTERNAL COMBUSTION	6.5 MW	633 TPY	LIMIT OF OPERATION HOURS AND AFTERCOOLERS	0	BACT-PSD
GENERAL ELECTRIC GAS TURBINES	SC	Apr-96	I.C. TURBINE	2,700 MMBTU/HR	885 LB/HR	GOOD COMBUSTION PRACTICES TO MINIMIZE EMISSIONS	0	BACT-PSD
CAROLINA POWER & LIGHT	NC	Apr-96	COMBUSTION TURBINE, 4 EACH	1,909 MMBTU/HR	512 LB/HR (OIL)	WATER INJECTION; FUEL SPEC: 0.04% N FUEL OIL	0	BACT-PSD
CAROLINA POWER & LIGHT	NC	Apr-96	COMBUSTION TURBINE, 4 EACH	1908 MMBTU/HR	158 LB/HR (GAS)	WATER INJECTION	0	BACT-PSD
MID-GEORGIA COGEN.	GA	Apr-96	COMBUSTION TURBINE (2), FUEL OIL	116 MW	20 PPMVD	WATER INJECTION WITH SCR	0	BACT-PSD
MID-GEORGIA COGEN.	GA	Apr-96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	9 PPMVD	DRY LOW NOX BURNER WITH SCR	0	BACT-PSD
GEORGIA GULF CORPORATION	LA	Mar-96	GENERATOR, NATURAL GAS FIRED TURBINE	1,123 MM BTU/HR	25 PPMV-CORR. TO 15%O2	CONTROL NOX USING STEAM INJECTION	0	BACT-PSD
SEMINOLE HARDEE UNIT 3	FL	Jan-96	COMBINED CYCLE COMBUSTION TURBINE	140 MW	15 PPM @ 15% O2	DRY LNB STAGED COMBUSTION	0	BACT-PSD
KEY WEST CITY ELECTRIC SYSTEM	FL	Sep-95	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	75 PPM @ 15% O2	WATER INJECTION	0	BACT-PSD
UNION CARBIDE CORPORATION	LA	Sep-95	GENERATOR, GAS TURBINE	1,313 MM BTU/HR	25 PPMV CORR. TO 15% O	DRY LOW NOX COMBUSTOR	0	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	PR	Jul-95	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	35 LB/HR AS NO2	STEAM INJECTION PLUS SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM. USE OF NO. 2 FUEL OIL WITH NITROGEN CONTENT NOT TO EXCEED 0.10% BY WEIGHT.	0	BACT-PSD
HIGGINSVILLE MUNICIPAL POWER FACILITY	MO	Jul-95	ADD OF A DUAL FUEL FIRED TWIN-PAC TURBINE	49 MW	42 PPM BY VOL 1 HR AVG (	CONTROLS TO REGULATE THE FUEL CONSUMPTION AND THE RATIO OF WATER TO FUEL BEING FIRED IN THE TURBINES	0	BACT-PSD
HIGGINSVILLE MUNICIPAL POWER FACILITY	MO	Jul-95	ADD OF A DUAL FUEL FIRED TWIN-PAC TURBINE	49 MW	75 PPM BY VOL 1 HR AVG (	CONTROLS TO REGULATE THE FUEL CONSUMPTION AND THE RATIO OF WATER TO FUEL BEING FIRED IN THE TURBINES	0	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	Jun-95	TURBINE, NATURAL GAS FIRED	240 MW	3.5 PPM @ 15% O2	SCR	0	LAER
PANDA-KATHLEEN, L.P.	FL	Jun-95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	15 PPM @ 15% O2	DRY LOW NOX BURNER	0	BACT-PSD
PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN)	PA	May-95	TURBINE, NATURAL GAS	590 MMBTU/HR	55 PPM @ 15% O2	STEAM INJECTION	75	RACT
MILAGRO, WILLIAMS FIELD SERVICE	NM	May-95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	9 PPM @ 15% O2	DRY LOW NOX (GENERAL ELECTRIC MODEL PG6541B)	94	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	FL	Apr-95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	15 PPM AT 15% OXYGEN	DRY LOW NOX BURNERS GE FRAME UNIT, CAN ANNULAR COMBUSTORS	0	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	FL	Apr-95	OIL FIRED COMBUSTION TURBINE	74 MW	42 PPM AT 15% OXYGEN	WATER INJECTION	0	BACT-PSD
LEDERLE LABORATORIES	NY	Apr-95	(2) GAS TURBINES (EP #S 00101&102)	110 MMBTU/HR	42 PPM, 18 LB/HR	STEAM INJECTION	0	BACT-PSD
PILGRIM ENERGY CENTER	NY	Apr-95	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&2)	1,400 MMBTU/HR	4.6 PPM, 23.6 LB/HR	STEAM INJECTION FOLLOWED BY SCR	0	BACT
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD	Mar-95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	15 PPM @ 15% O2	DRY BURN LOW NOX BURNERS	91	BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	Mar-95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	9 PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONTROL	0	LAER
LSP-COTTAGE GROVE, L.P.	MN	Mar-95	COMBUSTION TURBINE/GENERATOR	1,970 MMBTU/HR	4.5 PPM @ 15% O2 GAS	SELECTIVE CATALYTIC REDUCTION (SCR)	70	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	Feb-95	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	89 MW	360 TPY	WATER INJECTION.	0	BACT-PSD
MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	NM	Jan-95	TURBINES, NATURAL GAS (2)	5,500 HP	7.4 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY. DRY/LOW NOX	66	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	NY	Dec-94	SIEMENS V64.3 GAS TURBINE (EP #00001)	650 MMBTU/HR	25 PPM	WATER INJECTION	70	BACT
INDECK-OSWEGO ENERGY CENTER	NY	Oct-94	GE FRAME 6 GAS TURBINE	533 LBA/MBTU	42 PPM, 75.00 LB/HR	STEAM INJECTION	53	BACT
FULTON COGEN PLANT	NY	Sep-94	GE LM5000 GAS TURBINE	500 MMBTU/HR	36 PPM, 65 LB/HR	WATER INJECTION	59	BACT
CAROLINA POWER AND LIGHT	SC	Aug-94	STATIONARY GAS TURBINE	1,520 MMBTU/H	25 PPMDV @ 15% O2 (GAS)	WATER INJECTION	30	BACT-PSD
CAROLINA POWER AND LIGHT	SC	Aug-94	STATIONARY GAS TURBINE	1,520 MMBTU/H	62 PPMDV @ 15% O2 (OIL)	WATER INJECTION	30	BACT-PSD
BRUSH COGENERATION PARTNERSHIP	CO	Jul-94	TURBINE	350 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX BURNER	74	BACT-PSD
COLORADO POWER PARTNERSHIP	CO	Jul-94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBIN	42 PPM @ 15% O2	WATER INJECTION	66	BACT-PSD
MUDDY RIVER L.P.	NV	Jun-94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	303 LB/HR	LOW NOX BURNER	0	BACT-PSD
CSW NEVADA, INC.	NV	Jun-94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	273 LB/HR	DRY LOW NOX COMBUSTOR	0	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	OR	May-94	TURBINES, NATURAL GAS (2)	1,720 MMBTU	4.5 PPM @ 15% O2	SCR	82	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	May-94	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU/HR	25 PPM BY VOL 1 HR AVG (	LOW NOX BURNERS, AND WATER INJECTION	0	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	May-94	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1,345 MMBTU/HR	1,135 TPY (NO. 2 OIL)	LOW NOX BURNERS, AND WATER INJECTION	0	BACT-PSD
GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	GA	May-94	TURBINE, COMBUSTION, NATURAL GAS	80 MW	25 PPM	WATER INJECTION, FUEL SPEC: NATURAL GAS	0	BACT-PSD
WEST CAMPUS COGENERATION COMPANY	TX	May-94	GAS TURBINES	75 MW (TOTAL POWER)	200 TPY	INTERNAL COMBUSTION CONTROLS	0	BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	PA	Apr-94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	21 LB/HR	SCR WITH LOW NOX COMBUSTORS	47	BACT-OTHER
HERMISTON GENERATING CO.	OR	Apr-94	TURBINES, NATURAL GAS (2)	1,696 MMBTU	4.5 PPM @ 15% O2	SCR	82	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	Feb-94	TURBINE, NATURAL GAS (2)	1,510 MMBTU/H	12 PPMVD @15 % O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	Feb-94	TURBINE, FUEL OIL (2)	1,730 MMBTU/H	42 PPMVD @ 15 %O2	WATER INJECTION	0	BACT-PSD
TECO POLK POWER STATION	FL	Feb-94	TURBINE, SYNGAS (COAL GASIFICATION)	1,755 MMBTU/H	25 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
TECO POLK POWER STATION	FL	Feb-94	TURBINE, FUEL OIL	1,765 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	0	BACT-PSD
INTERNATIONAL PAPER	LA	Feb-94	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	25 PPMV 15% O2 TURBINE	DRY LOW NOX COMBUSTOR/COMBUSTION CONTROL	0	BACT
KAMINE/BESICORP CARTHAGE L.P.	NY	Jan-94	GE FRAME 6 GAS TURBINE	491 BTU/HR	42 PPM, 76.6 LB/HR	STEAM INJECTION	63	BACT
ORANGE COGENERATION LP	FL	Dec-93	TURBINE, NATURAL GAS, 2	368 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
PROJECT ORANGE ASSOCIATES	NY	Dec-93	GE LM-5000 GAS TURBINE	850 MMBTU/HR	25 PPM, 47 LB/HR	STEAM INJECTION, FUEL SPEC: NATURAL GAS ONLY	80	BACT
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	Oct-93	TURBINE, GAS-FIRED	11,257 HP	42 PPM @ 15% O2	SOLONOX COMBUSTOR, DRY LOW NOX TECHNOLOGY	66	BACT-PSD
FLORIDA GAS TRANSMISSION	FL	Sep-93	TURBINE, GAS	132 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD

Table B-2. Summary of Best Available Control Technology (BACT) Determinations for Nitrogen Oxide (NOx) Emissions

PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	VA	Sep-93	TURBINE, COMBUSTION, SIEMENS MODEL V84.2, 3	10.2 X109 SCF/YR NAT GAS	131 LB/HR(GAS); 339 OIL	DRY LOW NOX COMBUSTOR; DESIGN, WATER INJECTION	0	BACT-PSD
FLORIDA GAS TRANSMISSION COMPANY	AL	Aug-93	TURBINE, NATURAL GAS	12,600 BHP	0.58 GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY LOW NOX COMBUSTION	71	BACT-PSD
LOCKPORT COGEN FACILITY	NY	Jul-93	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	424 MMBTU/HR	42 PPM	STEAM INJECTION	70	BACT
ANITEC COGEN PLANT	NY	Jul-93	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001	451 MMBTU/HR	25 PPM, 41 LB/HR	NO CONTROLS	0	BACT-OTHER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	Jun-93	TURBINES, COMBUSTION, KEROSENE-FIRED (2)	640 MMBTU/H (EACH)	16 PPMDV	SCR	0	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	Jun-93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	8.3 PPMDV	SCR	0	BACT-PSD
TIGER BAY LP	FL	May-93	TURBINE, OIL	1,850 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	0	BACT-PSD
TIGER BAY LP	FL	May-93	TURBINE, GAS	1,615 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
INDECK ENERGY COMPANY	NY	May-93	GE FRAME 6 GAS TURBINE EP #00001	481 MMBTU/HR	32 PPM	STEAM INJECTION	58	BACT
PHOENIX POWER PARTNERS	CO	May-93	TURBINE (NATURAL GAS)	311 MMBTU/HR	22 PPM @ 15% O2	DRY LOW NOX COMBUSTION	0	BACT-OTHER
TRIGEN MITCHEL FIELD	NY	Apr-93	GE FRAME 6 GAS TURBINE	425 MMBTU/HR	60 PPM, 90 LB/HR	STEAM INJECTION	20	BACT
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, FUEL OIL	920 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, FUEL OIL	371 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, NATURAL GAS	869 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, NATURAL GAS	367 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	0	BACT-PSO
EAST KENTUCKY POWER COOPERATIVE	KY	Mar-93	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	1,492 MMBTU/H (EACH)	42 PPM @ 15% O2 (OIL)	WATER INJECTION	46	SEE NOTES
INTERNATIONAL PAPER CO. RIVERDALE MILL	AL	Jan-93	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER	40 MW	0.08 LB/MMBTU (GAS)	LOW NOX BURNERS (ON THE DUCT BURNER) STEAM INJECTION INTO THE TURBINE	0	BACT-PSD
OKLAHOMA MUNICIPAL POWER AUTHORITY	OK	Dec-92	TURBINE, COMBUSTION	58 MW	65 PPM @ 15% O2 (OIL)	COMBUSTION CONTROLS	83	BACT-OTHER
OKLAHOMA MUNICIPAL POWER AUTHORITY	OK	Dec-92	TURBINE, COMBUSTION	58 MW	25 PPM @ 15% O2 (GAS)	COMBUSTION CONTROLS	83	BACT-OTHER
AUBURNDALE POWER PARTNERS, LP	FL	Dec-92	TURBINE, OIL	1,170 MMBTU/H	42 PPMVD @ 15 % O2	STEAM INJECTION	0	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	Dec-92	TURBINE,GAS	1,214 MMBTU/H	15 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR	0	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	NY	Nov-92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2,133 MMBTU/HR (EACH)	4.5 PPM	SCR AND DRY LOW NOX	0	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	Nov-92	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	9 PPM (GAS)	DRY LOW NOX OR SCR	0	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	Nov-92	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	65 PPM (OIL)	DRY LOW NOX OR SCR	0	BACT-OTHER
KAMINE/BESICORP CORNING L.P.	NY	Nov-92	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	9 PPM	DRY LOW NOX OR SCR	0	BACT-OTHER
GRAYS FERRY CO. GENERATION PARTNERSHIP	PA	Nov-92	TURBINE (NATURAL GAS & OIL)	1,150 MMBTU	9 PPMVD (NAT. GAS)*	DRY LOW NOX BURNER, COMBUSTION CONTROL	0	BACT-OTHER
GOAL LINE, LP ICEFLOE	CA	Nov-92	TURBINE, COMBUSTION (NATURAL GAS) (42.4 MW)	385 MMBTU/HR	5 PPMVD @ 15% OXYGEN	WATER INJECTION & SCR W/ AUTOMATIC AMMONIA INJECT.	88	BACT-OTHER
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS	468 X10(6) BTU/HR #2 OIL	13 PPM	SCR	81	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS (TOTAL)	0.0	69.7 TPY	SCR	0	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N. GAS	9 PPM	SELECTIVE CATALYTIC REDUCTION (SCR)	75	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINE FACILITY, GAS	7.4 X10(7) GPY FUEL OIL	245 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR)	80	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINES (2) [EACH WITH A SF)	1.4 X10(9) BTU/H #2 OIL	66 LBS/HR/UNIT	WATER INJECTION AND SCR	80	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINE FACILITY, GAS	1,331 X10(7) SCF/Y NAT GAS	245 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR) W/ WATER INJEC	80	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINES (2) [EACH WITH A SF)	1.5 X10(9) BTU/HR N GAS	9 PPMDV/UNIT @ 15% O2	SCR WITH WATER INJECTION	60	BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	Sep-92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	88.6 TPY (EACH TURBINE)	LOW NOX COMBUSTOR	0	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	NY	Sep-92	GE FRAME 6 GAS TURBINE	498 MMBTU/HR	42 PPM, 78.6 LB/HR	WATER INJECTION	50	BACT
NORTHERN STATES POWER COMPANY	SD	Sep-92	TURBINE, SIMPLE CYCLE, 4 EACH	129 MW	24 PPM @ 15% O2 GAS	WATER INJECTION FOR GAS & DISTILLATION	0	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	Sep-92	TURBINE, COMBUSTION GAS (150 MW)	1,146 MMBTU/HR (GAS)*	9 PPM (GAS)	DRY LOW NOX	0	BACT-OTHER
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	Sep-92	TURBINE, COMBUSTION GAS (150 MW)	1,146 MMBTU/HR (GAS)*	42 PPM (OIL)	WATER INJECTOR	0	BACT-OTHER
WEPCO, PARIS SITE	WI	Aug-92	TURBINES, COMBUSTION (4)	0.0	65 PPM @ 15% O2 (OIL)	GOOD COMBUSTION PRACTICES	0	BACT-PSD
WEPCO, PARIS SITE	WI	Aug-92	TURBINES, COMBUSTION (4)	0.0	25 PPM @ 15% O2 (GAS)	GOOD COMBUSTION PRACTICES	0	BACT-PSD
FLORIDA POWER CORPORATION	FL	Aug-92	TURBINE, OIL	1,029 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	0	BACT-PSD
FLORIDA POWER CORPORATION	FL	Aug-92	TURBINE, OIL	1,866 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	0	BACT-PSD
NORTHWEST PIPELINE COMPANY	WA	Aug-92	TURBINE, GAS-FIRED	12,100 HP	186 PPM @ 15% O2	ADVANCED DRY LOW NOX COMBUSTOR (BY 07/01/95)	76	BACT-PSD
CNG TRANSMISSION	OH	Aug-92	TURBINE (NATURAL GAS) (3)	5,500 HP (EACH)	1.6 G/HP-HR*	LOW NOX COMBUSTION	0	BACT-OTHER
SARANAC ENERGY COMPANY	NY	Jul-92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123 MMBTU/HR (EACH)	9 PPM	SCR	0	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	Jul-92	TURBINE, OIL FIRED (2 EACH)	1,840 M BTU/HR	25 PPMVD, FUEL N AFLOW	MAXIMUM WATER INJECTION	0	BACT-PSD
MAUI ELECTRIC COMPANY, LTD/MAALAEA GENERATING STA	HI	Jul-92	TURBINE, COMBINED-CYCLE COMBUSTION	28 MW	42.3 LB/HR	WATER INJECTION	69	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	Jul-92	TURBINE, GAS FIRED (2 EACH)	1,817 M BTU/HR	25 PPM @ 15% O2	MAXIMUM WATER INJECTION	0	BACT-PSD
INDECK-YERKES ENERGY SERVICES	NY	Jun-92	GE FRAME 6 GAS TURBINE (EP #00001)	432 MMBTU/HR	42 PPM, 74 LB/HR	STEAM INJECTION	35	BACT
SELKIRK COGENERATION PARTNERS, L.P.	NY	Jun-92	COMBUSTION TURBINES (3) (252 MW)	1,173 MMBTU/HR (EACH)	9 PPM GAS	STEAM INJECTION AND SCR	0	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	Jun-92	COMBUSTION TURBINE (79 MW)	1,173 MMBTU/HR	25 PPM GAS	STEAM INJECTION	0	BACT-OTHER
NORTHWEST PIPELINE CORPORATION	CO	May-92	TURBINE, SOLAR TAURUS	45 MMBTU/HR	95 PPMVD (UNTIL 11/98)	DRY LOW NOX COMBUSTOR (BY 11/01/98)	0	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	Apr-92	TURBINE, GAS AND DUCT BURNER	1,360 MMBTU/H EACH	9 PPM @ 15% O2, GAS	SCR	0	BACT-PSD
KENTUCKY UTILITIES COMPANY	KY	Mar-92	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1,500 MM BTU/HR (EACH)	42 PPM @ 15% O2, N. GAS	WATER INJECTION	0	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION	1,175 MMBTU/H NAT. GAS	9 PPM @ 15% O2	SCR, STEAM INJECTION	91	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION	1,117 MMBTU/H NO2 FUEL OIL	15 PPM @ 15% O2	SCR, STEAM INJ.	91	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION, 2	0.0	191 T/YR/UNIT		0	BACT-PSD
THERMO INDUSTRIES, LTD.	CO	Feb-92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX TECH.	0	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	Feb-92	TURBINE, FUEL OIL #2	20 MW	42.3 LB/HR	COMBUSTOR WATER INJECTOR, WATER INJECTION	70	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	Feb-92	TURBINES, 8	1,032 MMBTU/H, NAT GAS	25 PPM @ 15% O2	MAX WATER INJECTION	0	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	Feb-92	TURBINES, 8	972 MMBTU/H, #2 OIL	0 SEE NOTES	MAX WATER INJECTION	0	BACT-PSD
LINDEN COGENERATION TECHNOLOGY	NJ	Jan-92	TURBINE, NATURAL GAS FIRED	50 X E12 BTU/YR	23.8 LB/HR	STEAM INJECTION AND SCR	95	BACT-PSD
ALYESKA PIPELINE SERVICE COMPANY	AK	Jan-92	SOLAR CENTAUR, 3	800 KW	150 PPMVD @ 15% O2	LOW NOX BURNERS	0	NSPS
KAMINE/BESICORP NATURAL DAM LP	NY	Dec-91	GE FRAME 6 GAS TURBINE	500 MMBTU/HR	42 PPM, 80.1 LB/HR	STEAM INJECTION	35	BACT
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	Dec-91	TURBINE, COMBUSTION	1,247 MM BTU/HR	207 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION	0	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	Dec-91	TURBINE, COMBUSTION	1,313 MM BTU/HR	119 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION	0	BACT-PSD
MAUI ELECTRIC COMPANY, LTD.	HI	Dec-91	TURBINE, FUEL OIL #2	28 MW	42 PPM	WATER INJECTION	71	BACT-PSD
KALAMAZOO POWER LIMITED	MI	Dec-91	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1,806 MMBTU/H	15 PPMV	DRY LOW NOX TURBINES	0	BACT-PSD
LAKE COGEN LIMITED	FL	Nov-91	TURBINE, OIL, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
LAKE COGEN LIMITED	FL	Nov-91	TURBINE, GAS, 2 EACH	42 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
SHELL PIPELINE CORPORATION	CA	Nov-91	GENERATOR, EMERGENCY, PROPANE FIRED	82 BHP	0.28 LB/H	3-WAY CATALYTIC CONVERTER	60	BACT-PSD
DE LA GUERRA POWER, INC	CA	Nov-91	ENGINE IC & GEN (1 OF 3)	380 HP	6.34 LB/D	NON-SELECTIVE CATALYTIC CONVERTER	90	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	Nov-91	TURBINE, GAS, 4 EACH	35 MW	42 PPM @ 15% O2	WET INJECTION	70	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	Nov-91	TURBINE, OIL, 4 EACH	35 MW	65 PPM @ 15% O2	WET INJECTION	0	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	Oct-91	TURBINE, GAS FIRED, SOLAR MODEL H	5,500 HP	9 PPM @ 15% O2	HIGH TEMP SELECT. CAT. REDUCTION	93	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5,500 HP	84.9 PPM @ 15% O2	LEAN BURN	0	NSPS
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5,500 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	51	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5,600 HP	85.1 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	0	NSPS
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	51	BACT-PSD
FLORIDA POWER GENERATION	FL	Oct-91	TURBINE, OIL, 6 EACH	93 MW	42 PPM @ 15% O2	WET INJECTION	0	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12,000 HP	225 PPM @ 15% O2	LEAN BURN	0	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12,000 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	80	BACT-PSD
NUGGET OIL CO.	CA	Oct-91	GENERATOR, STEAM, GAS FIRED	63 MMBTU/H	0.043 LB/MMBTU	LOW NOX BURNER AND FLUE GAS RECIRCULATION*	57	BACT-PSD
CAROLINA POWER AND LIGHT CO.	SC	Sep-91	TURBINE, I.C.	80 MW	292 LB/H	WATER INJECTION	50	BACT-PSD
ENRON LOUISIANA ENERGY COMPANY	LA	Aug-91	TURBINE, GAS, 2	39 MMBTU/H	40 PPM @ 15% O2	H2O INJECT 0.67 LB/LB	71	BACT-PSD
ALGONQUIN GAS TRANSMISSION CO.	RI	Jul-91	TURBINE, GAS, 2	49 MMBTU/H	100 PPM @ 15% O2	LOW NOX COMBUSTION	0	BACT-OTHER

Table B-2. Summary of Best Available Control Technology (BACT) Determinations for Nitrogen Oxide (NOx) Emissions

CHARLES LARSEN POWER PLANT	FL	Jul-91	TURBINE, OIL, 1 EACH	80 MW	42 PPM @ 15% O2	WET INJECTION	0	BACT-PSD
CHARLES LARSEN POWER PLANT	FL	Jul-91	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	WET INJECTION	0	BACT-PSD
SUMAS ENERGY INC.	WA	Jun-91	TURBINE, NATURAL GAS	88 MW	6 PPM @ 15% O2	SCR	90	BACT-PSD
SAGUARO POWER COMPANY	NV	Jun-91	COMBUSTION TURBINE GENERATOR	35 MW	18.0 PPH (WINTER)	SELECTIVE CATALYTIC REDUCTION (SCR)	80	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, OIL, 2 EACH	400 MW	66 PPM @ 15% O2	LOW NOX COMBUSTORS	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, GAS, 4 EACH	400 MW	25 PPM @ 15% O2	LOW NOX COMBUSTORS	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, CO, 4 EACH	400 MW	42 PPM @ 15% O2	LOW NOX COMBUSTORS	0	BACT-PSD
GRANITE ROAD LIMITED	CA	May-91	TURBINE, GAS, ELECTRIC GENERATION	461 MMBTU/H*	3.5 PPMVD @ 15% O2	SCR, STEAM INJECTION	97	BACT-PSD
NORTHERN CONSOLIDATED POWER	PA	May-91	TURBINES, GAS, 2	35 KW EACH	26 PPM @ 15% O2	STEAM INJECTION/+SCR IN 1997	85	OTHER
CIMARRON CHEMICAL	CO	Mar-91	TURBINE #1, GE FRAME 5	33 MW	25 PPM @ 15% O2	WATER INJECTION	0	OTHER
CIMARRON CHEMICAL	CO	Mar-91	TURBINE #2, GE FRAME 6	33 MW	9 PPM @ 15% O2	SCR	0	OTHER
SEMINOLE FERTILIZER CORPORATION	FL	Mar-91	TURBINE, GAS	26 MW	9 PPM @ 15% O2	SCR	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Mar-91	TURBINE, GAS, 4 EACH	240 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Mar-91	TURBINE, OIL, 4 EACH	0.0	65 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	MO	Mar-91	GENERATION OF ELECTRICAL POWER	753 MMBTU/HR	42 PPM BY VOL 1 HR AVG (	WATER INJECTION	0	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	MO	Mar-91	GENERATION OF ELECTRICAL POWER	752 MMBTU/HR	65 PPM BY VOL 1 HR AVG (	WATER INJECTION	0	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	MO	Mar-91	GENERATION OF ELECTRICAL POWER	585 MMBTU/HR.	42 PPM BY VOL 1 HR AVG (	WATER INJECTION	0	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	MO	Mar-91	GENERATION OF ELECTRICAL POWER	585 MMBTU/HR.	65 PPM BY VOL 1 HR AVG (	WATER INJECTION	0	BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	Jan-91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	61.3 LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT	0	BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	Jan-91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	61.3 LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT	0	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NJ	Nov-90	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	0.033 LB/MMBTU	STEAM INJECTION AND SCR	94	BACT-PSD
NORTHERN NATURAL GAS COMPANY	IA	Sep-90	ENGINE, COMPRESSOR	4,000 HP	1.8 G/B-HP-H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
NORTHERN NATURAL GAS COMPANY	IA	Sep-90	ENGINES, COMPRESSOR, 2	2,000 HP EACH	1.8 G/B-HP-H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
TBG COGEN COGENERATION PLANT	NY	Aug-90	GE LM2500 GAS TURBINE	215 MMBTU/HR	75 PPM + FBN CORRECTIO	WATER INJECTION	60	BACT
PEPCO - CHALK POINT PLANT	MD	Jun-90	TURBINE, 105 MW NATURAL GAS FIRED ELECTRIC	105 MW	77 PPM @ 15% O2	DRY PREMIX AND WATER INJECTION	0	BACT-PSD
PEPCO - CHALK POINT PLANT	MD	Jun-90	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84 MW	25 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	0	BACT-PSD
PACIFIC GAS TRANSMISSION COMPANY	OR	Jun-90	TURBINE GAS, COMPRESSOR STATION	110 MMBTU/HR	199 PPM @ 15% O2	LOW NOX BURNER DESIGN	30	NSPS
PEPCO - STATION A	MD	May-90	TURBINE, 134 MW NATURAL GAS FIRED	126 MW	42 PPM @ 15% O2	WATER INJECTION	0	BACT-PSD
PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	NJ	Feb-90	TURBINE, NATURAL GAS FIRED	1,000 MMBTU/HR	0.044 LB/MMBTU	STEAM INJECTION AND SCR	93	BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	Dec-89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	300 LBS/HR	WATER INJECTION	0	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	MA	Nov-89	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	25 PPM @ 15% O2	WATER INJECTION	0	BACT-OTHER
PACIFIC GAS TRANSMITION	OR	Nov-89	TURBINE, NAT. GAS	14,600 HP	42 PPM @ 15% O2	LOW NOX BURNERS	75	BACT-PSD
SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	MD	Oct-89	TURBINE, NATURAL GAS FIRED ELECTRIC	90 MW	199 LB/HR	WATER INJECTION	0	BACT-PSD
KINGSBURG ENERGY SYSTEMS	CA	Sep-89	TURBINE, NATURAL GAS FIRED, DUCT BURNER	25 MW	6 PPM @ 15% O2	SCR, STEAM INJECTION	90	BACT-PSD
MEGAN-RACINE ASSOCIATES, INC	NY	Aug-89	GE LM5000-N COMBINED CYCLE GAS TURBINE	401 LB/MMBTU	42 PPMDV @ 15% O2	WATER INJECTION	60	BACT

Note: PSD= Prevention of Significant Deterioration
BACT= Best Available Control Technology
LAER= Lowest Achievable Emission Rate

Table B-3. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs		Basis of Cost Component
Direct Capital Costs			
SCR Associated Equipment	$2,835,000		Vendor Estimate
Ammonia Storage Tank	$137,529	$35	per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$66,758		Vatavauk,1990
Instrumentation	$50,000		Additional NO_x Monitor and System
Taxes	$170,100	6%	of SCR Associated Equipment and Catalyst
Freight	$141,750	5%	of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$3,401,137		
Direct Installation Costs			
Foundation and supports	$272,091	8%	of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$476,159	14%	of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$136,045	4%	of TDCC and RCC;OAQPS Cost Control Manual
Piping	$68,023	2%	of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$34,011	1%	of TDCC and RCC;OAQPS Cost Control Manual
Painting	$34,011	1%	of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000		Engineering Estimate
Buildings	$15,000		Engineering Estimate
Total Direct Installation Costs (TDIC)	$1,040,341		
Total Capital Costs (TCC)	$4,441,478	Sum of TDCC, TDIC and RCC	
Indirect Costs			
Engineering	$444,148	10%	of Total Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000		Engineering Estimate
Construction and Field Expense	$222,074	5%	of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$444,148	10%	of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$88,830	2%	of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$44,415	1%	of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$133,244	3%	of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$1,426,858		
Total Direct, Indirect and Capital Costs (TDICC)	$5,868,336	Sum of TCC and TInCC	

Table B-4. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	$18,720	24 hours/week at $15/hr
Supervision	$2,808	.15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$67,064	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	Engineering Estimate
Inventory Cost	$71,590	Capital Recovery (10.98%) for 1/3 catalyst
Catalyst Cost	$493,000	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$20,045	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$688,227	
Energy Costs		
Electrical	$37,968	80kW/h for SCR & 200kW/h for cooling @ $0.04/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	$207,129	0.5% of MW output; EPA, 1993 (Page 6-20)
Total Energy Costs (TEC)	$245,097	
Indirect Annual Costs		
Overhead	$53,155	60% of Operating/Supervision Labor and Ammonia
Property Taxes	$58,683	1% of Total Capital Costs
Insurance	$58,683	1% of Total Capital Costs
Annualized Total Direct Capital	$644,343	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$814,865	
Total Annualized Costs	$1,748,189	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$11,354	NO_x Reduction Only
	$20,629	Net Emission Reduction

Table B-5. Summary of Best Available Control Technology (BACT) Determinations for Carbon Monoxide (CO) Emissions

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity	(size)	CO Emission Limit	Control Method	Efficiency (%)	Type
BUCKNELL UNIVERSITY	PA	Nov-97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5	MW	50 PPMV@15%O2	GOOD COMBUSTION	0	BACT-OTHER
LORDSBURG L.P.	NM	Jun-97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100	MW	27 LBS/HR	DRY LOW-NOX TECHNOLOGY BY MAINTAINING PROPER AIR- FUEL RATIO.	0	BACT-PSD
MEAD COATED BOARD, INC.	AL	Mar-97	COMBINED CYCLE TURBINE (25 MW)	568	MMBTU/HR	28 PPMVD@15% O2 (GAS)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	0	BACT-PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	LA	Mar-97	TURBINE/HSRG, GAS COGENERATION	450	MM BTU/HR	70 LB/HR	COMBUSTION DESIGN AND CONSTRUCTION.	0	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	Feb-97	COMBUSTION TURBINE, NATURAL GAS	100	MW	0 SEE FACILITY NOTES	GOOD COMBUSTION PRACTICES	0	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	Nov-96	COMBUSTION TURBINE, NATURAL GAS	100	MW	0 SEE P2	GOOD COMBUSTION PRACTICES	0	BACT-PSD
ECOELECTRICA, L.P.	PR	Oct-96	TURBINES, COMBINED-CYCLE COGENERATION	461	MW	33 PPMDV	COMBUSTION CONTROLS.	0	BACT-PSD
ECOELECTRICA, L.P.	PR	Oct-96	TURBINES, COMBINED-CYCLE COGENERATION	461	MW	100 PPMDV AT MIN. LOAD	COMBUSTION CONTROLS.	0	BACT-PSD
BLUE MOUNTAIN POWER, LP	PA	Jul-96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153	MW	3.1 PPM @ 15% O2	OXIDATION CATALYST 18 PPM @ 15% O2 WHEN FIRING NO. 2 OIL AT 75% NO LIMIT SET TO 22.1 PPM	80	OTHER
COMMONWEALTH CHESAPEAKE CORPORATION	VA	May-96	3 COMBUSTION TURBINES (OIL-FIRED)	6,000	HRS/YR	96 TPY	GOOD COMBUSTION OPERATING PRACTICES	0	BACT/NSPS
PORTSIDE ENERGY CORP.	IN	May-96	TURBINE, NATURAL GAS-FIRED	63	MEGAWATT	40 LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 40 PPMVD AT 15% OXYGEN.	0	BACT-PSD
PORTSIDE ENERGY CORP.	IN	May-96	TURBINE, NATURAL GAS-FIRED	63	MEGAWATT	12 LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 10 PPMVD AT 15% OXYGEN.	0	BACT-PSD
GENERAL ELECTRIC GAS TURBINES	SC	Apr-96	I.C. TURBINE	2,700	MMBTU/HR	27,169 LB/HR	GOOD COMBUSTION PRACTICES TO MINIMIZE EMISSIONS	0	BACT-PSD
CAROLINA POWER & LIGHT	NC	Apr-96	COMBUSTION TURBINE, 4 EACH	1,906	MMBTU/HR	81 LB/HR	COMBUSTION CONTROL	0	BACT-PSD
CAROLINA POWER & LIGHT	NC	Apr-96	COMBUSTION TURBINE, 4 EACH	1,906	MMBTU/HR	80 LB/HR	COMBUSTION CONTROL	0	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MS	Apr-96	COMBUSTION TURBINE, COMBINED CYCLE	1,299	MMBTU/HR NAT GAS	26.3 PPM @ 15% O2, GAS	GOOD COMBUSTION CONTROLS	0	BACT-PSD
MID-GEORGIA COGEN.	GA	Apr-96	COMBUSTION TURBINE (2), FUEL OIL	118	MW	30 PPMVD	COMPLETE COMBUSTION	0	BACT-PSD
MID-GEORGIA COGEN.	GA	Apr-96	COMBUSTION TURBINE (2), NATURAL GAS	118	MW	10 PPMVD	COMPLETE COMBUSTION	0	BACT-PSD
GEORGIA GULF CORPORATION	LA	Mar-96	GENERATOR, NATURAL GAS FIRED TURBINE	1,123	MM BTU/HR	972 TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION	0	BACT-PSD
SEMINOLE HARDEE UNIT 3	FL	Jan-96	COMBINED CYCLE COMBUSTION TURBINE	140	MW	20 PPM (NAT. GAS)	DRY LNB GOOD COMBUSTION PRACTICES	0	BACT-PSD
KEY WEST CITY ELECTRIC SYSTEM	FL	Sep-95	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23	MW	20 PPM @ 15% O2 FULL LD	GOOD COMBUSTION	0	BACT-PSD
UNION CARBIDE CORPORATION	LA	Sep-95	GENERATOR, GAS TURBINE	1,313	MM BTU/HR	199 LB/HR	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE	0	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	PR	Jul-95	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EAC	248	MW	20 LB/HR	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GOOD COMBUSTION PRACTICES.	0	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	PR	Jul-95	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EAC	248	MW	104 LB/HR	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GOOD COMBUSTION PRACTICES.	0	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	Jun-95	TURBINE, NATURAL GAS FIRED	240	MW	4 PPM @ 15% O2		0	LAER
PANDA-KATHLEEN, L.P.	FL	Jun-95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115M	75	MW	25 PPM @ 15% O2	COMBUSTION CONTROLS STANDARD ONLY APPLIES IF GE CT IS SELECTED, THE ABB CT WAS LESS THAN SIGNIFICANT EMIS. INCR FOR CO	0	BACT-PSD
MILAGRO, WILLIAMS FIELD SERVICE	NM	May-95	TURBINE/COGEN, NATURAL GAS (2)	900	MMCF/DAY	28 PPM @ 15% O2		0	BACT-PSD
LEDERLE LABORATORIES	NY	Apr-95	(2) GAS TURBINES (EP #S 00101&102)	110	MMBTU/HR	46 PPM, 12.6 LB/HR		0	BACT-OTHER
PILGRIM ENERGY CENTER	NY	Apr-95	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&2)	1,400	MMBTU/HR	10 PPM, 29.0 LB/HR		0	BACT-OTHER
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD	Mar-95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140	MW	20 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	0	BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	Mar-95	TURBINE/HRSG, GAS COGENERATION	450	MM BTU/HR	28 LB/HR	PROPER OPERATION	0	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	Feb-95	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	89	MW	428 TPY	GOOD COMBUSTION CONTROL	0	BACT-PSD
MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	NM	Jan-95	TURBINES, NATURAL GAS (2)	8,500	HP	13 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY.	66	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	NY	Dec-94	SIEMENS V84.3 GAS TURBINE (EP #00001)	650	MMBTU/HR	9.5 PPM	NO CONTROLS	0	BACT-OTHER
INDECK-OSWEGO ENERGY CENTER	NY	Oct-94	GE FRAME 6 GAS TURBINE	533	LBAMBTU	10 PPM, 10.00 LB/HR	NO CONTROLS	0	BACT-OTHER
FULTON COGEN PLANT	NY	Sep-94	GE LM5000 GAS TURBINE	500	MMBTU/HR	107 PPM, 120 LB/HR	NO CONTROLS	0	BACT-OTHER
CAROLINA POWER AND LIGHT	SC	Aug-94	STATIONARY GAS TURBINE	1,520	MMBTU/H	702 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	0	BACT-PSD
CAROLINA POWER AND LIGHT	SC	Aug-94	STATIONARY GAS TURBINE	1,520	MMBTU/H	414 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	0	BACT-PSD
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	Jul-94	NATURAL GAS-FIRED COMPRESSOR ENGINE	520	HORSEPOWER	1.7 LBS/HR	GOOD COMBUSTION	0	BACT
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	Jul-94	2 GAS-FIRED GENERATOR ENGINES	385	HORSEPOWER	1.3 LBS/HR	GOOD COMBUSTION	0	BACT
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	Jul-94	1 GAS-FIRED GENERATOR ENGINE	377	HORSEPOWER	1.9 LBS/HR	GOOD COMBUSTION	0	BACT
COLORADO POWER PARTNERSHIP	CO	Jul-94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385	MMBTU/H EACH TURBINE	22 PPM @ 15% O2		0	BACT-PSD
MUDDY RIVER L.P.	NV	Jun-94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140	MEGAWATT	77 LB/HR	FUEL SPEC: NATURAL GAS	0	BACT-PSD
CSW NEVADA, INC.	NV	Jun-94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140	MEGAWATT	83 LB/HR	FUEL SPEC: NATURAL GAS	0	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	OR	May-94	TURBINES, NATURAL GAS (2)	1,720	MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	0	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	May-94	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1,345	MMBTU/HR	120 TPY	NONE	0	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	May-94	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1,345	MMBTU/HR	1200 TPY	NONE	0	BACT-PSD
NAVY PUBLIC WORKS CENTER	VA	May-94	1 EMERGENCY GENERATOR	1,500	KW	14.4 TPY	RETARD TIMING 8 DEGREES	0	NSPS
WEST CAMPUS COGENERATION COMPANY	TX	May-94	GAS TURBINES	75	MW (TOTAL POWER)	300 TPY	INTERNAL COMBUSTION CONTROLS	0	BACT
HERMISTON GENERATING CO.	OR	Apr-94	TURBINES, NATURAL GAS (2)	1,696	MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	0	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	Feb-94	TURBINE, NATURAL GAS (2)	1,510	MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES	0	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	Feb-94	TURBINE, FUEL OIL (2)	1,730	MMBTU/H	30 PPMVD	GOOD COMBUSTION PRACTICES	0	BACT-PSD
TECO POLK POWER STATION	FL	Feb-94	TURBINE, SYNGAS (COAL GASIFICATION)	1,755	MMBTU/H	25 PPMVD	GOOD COMBUSTION	0	BACT-PSD
TECO POLK POWER STATION	FL	Feb-94	TURBINE, FUEL OIL	1,765	MMBTU/H	40 PPMVD	GOOD COMBUSTION	0	BACT-PSD
INTERNATIONAL PAPER	LA	Feb-94	TURBINE/HRSG, GAS COGEN	338	MM BTU/HR TURBINE	166 LB/HR	COMBUSTION CONTROL	0	BACT
KAMINE/BESICORP CARTHAGE L.P.	NY	Jan-94	GE FRAME 6 GAS TURBINE	491	BTU/HR	10 PPM, 11.0 LB/HR	NO CONTROLS	0	BACT-OTHER
ORANGE COGENERATION LP	FL	Dec-93	TURBINE, NATURAL GAS, 2	368	MMBTU/H	30 PPMVD	GOOD COMBUSTION	0	BACT-PSD
PROJECT ORANGE ASSOCIATES	NY	Dec-93	GE LM-5000 GAS TURBINE	550	MMBTU/HR	92 LB/HR TEMP > 20F	NO CONTROLS	0	BACT-OTHER
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	Oct-93	TURBINE, GAS-FIRED	11,257	HP	50 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	VA	Sep-93	TURBINE, COMBUSTION, SIEMENS MODEL V84 2, S	10.2	X109 SCF/YR NAT GAS	26 LB/HR	GOOD COMBUSTION OPERATING PRACTICES	0	BACT-PSD
FLORIDA GAS TRANSMISSION COMPANY	AL	Aug-93	TURBINE, NATURAL GAS	12,600	BHP	0.42 GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY COMBUSTION CONTROLS	0	BACT-PSD
LOCKPORT COGEN FACILITY	NY	Jul-93	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	424	MMBTU/HR	10 PPM	NO CONTROLS	0	BACT-OTHER
ANITEC COGEN PLANT	NY	Jul-93	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001	451	MMBTU/HR	38 PPM, 33 LB/HR	BAFFLE CHAMBER	80	SEE NOTE #4
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	Jun-93	TURBINES, COMBUSTION, KEROSENE-FIRED (2)	640	MMBTU/H (EACH)	2.8 PPMDV	OXIDATION CATALYST	0	OTHER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	Jun-93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	817	MMBTU/HR (EACH)	1.8 PPMDV	OXIDATION CATALYST	0	OTHER
PSI ENERGY, INC. WABASH RIVER STATION	IN	May-93	COMBINED CYCLE SYNGAS TURBINE	1,775	MMBTU/HR	15 LESS THAN PPM	OPERATION PRACTICES AND GOOD COMBUSTION, COMBINED CYCLE SYNGAS TURBINE	0	BACT-PSD
TIGER BAY LP	FL	May-93	TURBINE, OIL	1,850	MMBTU/H	98.4 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
TIGER BAY LP	FL	May-93	TURBINE, GAS	1,615	MMBTU/H	49 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
INDECK ENERGY COMPANY	NY	May-93	GE FRAME 6 GAS TURBINE EP #00001	491	MMBTU/HR	40 PPM	NO CONTROLS	0	BACT-OTHER
TRIGEN MITCHEL FIELD	NY	Apr-93	GE FRAME 6 GAS TURBINE	425	MMBTU/HR	10 PPM, 10.0 LB/HR	NO CONTROLS	0	BACT-OTHER
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, FUEL OIL	926	MMBTU/H	65 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, FUEL OIL	371	MMBTU/H	76 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, NATURAL GAS	869	MMBTU/H	54 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	Apr-93	TURBINE, NATURAL GAS	387	MMBTU/H	40 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
EAST KENTUCKY POWER COOPERATIVE	KY	Mar-93	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	1,492	MMBTU/H (EACH)	75 LBS/H (EACH)	PROPER COMBUSTION TECHNIQUES	0	BACT-OTHER
INTERNATIONAL PAPER CO. RIVERDALE MILL	AL	Jan-93	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNE	40	MW	22 LB/HR	DESIGN	0	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	Dec-92	TURBINE, OIL	1,170	MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES	0	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	Dec-92	TURBINE,GAS	1,214	MMBTU/H	15 PPMVD	GOOD COMBUSTION PRACTICES	0	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	NY	Nov-92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2,133	MMBTU/HR (EACH)	13 PPM	COMBUSTION CONTROLS	0	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	Nov-92	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	850	MMBTU/HR	9.5 PPM	COMBUSTION CONTROLS	0	BACT-OTHER
GRAYS FERRY CO. GENERATION PARTNERSHIP	PA	Nov-92	TURBINE (NATURAL GAS & OIL)	1,150	MMBTU	0.0055 LB/MMBTU (GAS)*	COMBUSTION	0	BACT-OTHER
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS	468	X10(6) BTU/HR #2 OIL	11 LBS/HR	GOOD COMBUSTION	0	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS (TOTAL)	0		48 TPY	GOOD COMBUSTION	0	BACT-PSD

[redacted]

Table B-5. Summary of Best Available Control Technology (BACT) Determinations for Carbon Monoxide (CO) Emissions

Facility Name	State	Permit Issue Date	Unit/Process Description	Capacity (size)	CO Emission Limit	Control Method	Efficiency (%)	Type
BEAR ISLAND PAPER COMPANY, L.P.	VA	Oct-92	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N. GAS	11 LBS/HR	GOOD COMBUSTION	0	BACT-PSD
PHILADELPHIA SOUTHWEST WATER TREATMENT PLANT	PA	Oct-92	ENGINES (2) (NATURAL GAS)	443 KW (EACH)	0	LEAN BURN ENGINE	0	OTHER
PHILADELPHIA NORTHEAST WATER TREATMENT PLANT	PA	Oct-92	ENGINES (3) (NATURAL GAS)	443 KW (EACH)	0	LEAN BURN ENGINE	0	OTHER
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINE FACILITY, GAS	7.44 X10(7) GPY FUEL OIL	250 TOTAL TPY	GOOD COMBUSTION PRACTICES	0	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINES (2) [EACH WITH A SF]	1.38 X10(9) BTU/H #2 OIL	68 LBS/HR/UNIT	GOOD COMBUSTION PRACTICES	0	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINE FACILITY, GAS	1,331 X10(7) SCF/Y NAT GAS	250 TOTAL TPY	GOOD COMBUSTION PRACTICES	0	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	Sep-92	TURBINES (2) [EACH WITH A SF]	1.51 X10(9) BTU/HR N GAS	57 LBS/HR/UNIT	GOOD COMBUSTION PRACTICES	0	BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	Sep-92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	153 TPY (EACH TURBINE)	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR	0	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	NY	Sep-92	GE FRAME 6 GAS TURBINE	498 MMBTU/HR	9 PPM, 11.0 LB/HR	NO CONTROLS	0	BACT-OTHER
NORTHERN STATES POWER COMPANY	SD	Sep-92	TURBINE, SIMPLE CYCLE, 4 EACH	129 MW	50 PPM FOR GAS	GOOD COMBUSTION TECHNIQUES	0	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	Sep-92	TURBINE, COMBUSTION GAS (150 MW)	1,148 MMBTU/HR (GAS)*	8.5 PPM	COMBUSTION CONTROL	0	BACT-OTHER
WEPCU, PARIS SITE	WI	Aug-92	TURBINES, COMBUSTION (4)	0	25 LBS/HR (SEE NOTES)		0	BACT-PSD
FLORIDA POWER CORPORATION	FL	Aug-92	TURBINE, OIL	1,029 MMBTU/H	54 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
FLORIDA POWER CORPORATION	FL	Aug-92	TURBINE, OIL	1,866 MMBTU/H	79 LB/H	GOOD COMBUSTION PRACTICES	0	BACT-PSD
CNG TRANSMISSION	OH	Aug-92	TURBINE (NATURAL GAS) (3)	5,500 HP (EACH)	0.015 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS	0	OTHER
SARANAC ENERGY COMPANY	NY	Jul-92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123 MMBTU/HR (EACH)	3 PPM	OXIDATION CATALYST	0	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	Jul-92	TURBINE, OIL FIRED (2 EACH)	1,840 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	0	BACT-PSD
MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING STA	HI	Jul-92	TURBINE, COMBINED-CYCLE COMBUSTION	76 MW	27 LB/HR	COMBUSTION TECHNOLOGY/DESIGN	0	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	Jul-92	TURBINE, GAS FIRED (2 EACH)	1,817 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	0	BACT-PSD
INDECK-YERKES ENERGY SERVICES	NY	Jun-92	GE FRAME 6 GAS TURBINE (EP #00001)	432 MMBTU/HR	10 PPM, 10 LB/HR	NO CONTROLS	0	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	Jun-92	COMBUSTION TURBINES (2) (252 MW)	1,173 MMBTU/HR (EACH)	10 PPM	COMBUSTION CONTROLS	0	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	Jun-92	COMBUSTION TURBINE (79 MW)	1,173 MMBTU/HR	25 PPM	COMBUSTION CONTROL	0	BACT-OTHER
TENASKA WASHINGTON PARTNERS, L.P.	WA	May-92	COGENERATION PLANT, COMBINED CYCLE	1.83 MMBTU/HR	20 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	Apr-92	TURBINE, GAS AND DUCT BURNER	1,360 MMBTU/H EACH	11 PPM @ 15% O2, GAS		0	BACT-PSD
KENTUCKY UTILITIES COMPANY	KY	Mar-92	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1,500 MM BTU/HR (EACH)	75 LB/HR (EACH)	COMBUSTION CONTROL	0	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION	1,175 MMBTU/H NAT. GAS	62 LB/H/UNIT	FURNACE DESIGN	91	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION	1,117 MMBTU/H NO2 FUEL OIL	62 LB/H/UNIT	FURNACE DESIGN	91	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	Mar-92	TURBINE, COMBUSTION, 2	0	229 T/YR/UNIT		0	BACT-PSD
THERMO INDUSTRIES, LTD.	CO	Feb-92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	Feb-92	TURBINE, FUEL OIL #2	20 MW	27 LB/HR @ 100% PEAKLD	COMBUSTION DESIGN	0	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	Feb-92	TURBINE, FUEL OIL #2	20 MW	56 LB/H @ 75-<100% PKLD	COMBUSTION DESIGN	0	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	Feb-92	TURBINE, FUEL OIL #2	20 MW	181 LB/H @ 50-<75% PKLD	COMBUSTION DESIGN	0	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	Feb-92	TURBINE, FUEL OIL #2	20 MW	476 LB/H @ 25-<50% PKLD	COMBUSTION DESIGN	0	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	Feb-92	TURBINES, 8	1,032 MMBTU/H, NAT GAS	5 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	0	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	Feb-92	TURBINES, 8	972 MMBTU/H, #2 OIL	5 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	0	BACT-PSD
KAMINE/BESICORP NATURAL DAM LP	NY	Dec-91	GE FRAME 9 GAS TURBINE	500 MMBTU/HR	0.02 LB/MMBTU, 10 LB/HR	NO CONTROLS	0	BACT-OTHER
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	Dec-91	TURBINE, COMBUSTION	1,247 MM BTU/HR	60 LB/HR	COMBUSTION CONTROL	0	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	Dec-91	TURBINE, COMBUSTION	1,313 MM BTU/HR	58 LB/HR	COMBUSTION CONTROL	0	BACT-PSD
MAUI ELECTRIC COMPANY, LTD.	HI	Dec-91	TURBINE, FUEL OIL #2	29 MW	0 SEE NOTES	GOOD COMBUSTION PRACTICES	0	BACT-PSD
KALAMAZOO POWER LIMITED	MI	Dec-91	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1,806 MMBTU/H	20 PPMV	DRY LOW NOX TURBINES	0	BACT-PSD
LAKE COGEN LIMITED	FL	Nov-91	TURBINE, OIL, 2 EACH	42 MW	78 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
LAKE COGEN LIMITED	FL	Nov-91	TURBINE, GAS, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	Nov-91	TURBINE, GAS, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	Nov-91	TURBINE, OIL, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	Oct-91	TURBINE, GAS-FIRED	48 MMBTU/H	7.74 PPM @ 15% O2	HIGH TEMPERATURE OXIDATION CATALYST	80	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	Oct-91	TURBINE, GAS FIRED, SOLAR MODEL H	5,500 HP	7.74 PPM @ 15% O2	HIGH TEMP OXIDATION CATALYST	80	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5,500 HP	10.5 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	0	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, GAS, SOLAR CENTAUR H	5,500 HP	10.5 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	0	BACT-PSD
FLORIDA POWER GENERATION	FL	Oct-91	TURBINE, OIL, 8 EACH	93 MW	54 LB/H	COMBUSTION CONTROL	0	BACT-PSD
EL PASO NATURAL GAS	AZ	Oct-91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12,000 HP	60 PPM @ 15% O2	LEAN BURN	0	BACT-PSD
CAROLINA POWER AND LIGHT CO.	SC	Sep-91	TURBINE, I.C.	80 MW	60 LB/H		0	BACT-PSD
ENRON LOUISIANA ENERGY COMPANY	LA	Aug-91	TURBINE, GAS, 2	39 MMBTU/H	60 PPM @ 15% O2	BASE CASE, NO ADDITIONAL CONTROLS	0	BACT-PSD
ALGONQUIN GAS TRANSMISSION CO.	RI	Jul-91	TURBINE, GAS, 2	49 MMBTU/H	0.114 LB/MMBTU	GOOD COMBUSTION PRACTICES	0	BACT-OTHER
CHARLES LARSEN POWER PLANT	FL	Jul-91	TURBINE, OIL, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
CHARLES LARSEN POWER PLANT	FL	Jul-91	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
SUMAS ENERGY INC.	WA	Jun-91	TURBINE, NATURAL GAS	88 MW	8 PPM @ 15% O2	CO CATALYST	80	BACT-PSD
SAGUARO POWER COMPANY	NV	Jun-91	COMBUSTION TURBINE GENERATOR	34.5 MW	9 PPH	CONVERTER (CATALYTIC)	90	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, OIL, 2 EACH	400 MW	33 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, GAS, 4 EACH	400 MW	30 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Jun-91	TURBINE, CO, 4 EACH	400 MW	33 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
NORTHERN CONSOLIDATED POWER	PA	May-91	TURBINES, GAS, 2	34.8 KW EACH	110 T/YR	OXIDATION CATALYST	80	OTHER
LAKEWOOD COGENERATION, L.P.	NJ	Apr-91	TURBINES (#2 FUEL OIL) (2)	1,190 MMBTU/HR (EACH)	0.06 LB/MMBTU	TURBINE DESIGN	0	BACT-OTHER
LAKEWOOD COGENERATION, L.P.	NJ	Apr-91	TURBINES (NATURAL GAS) (2)	1,190 MMBTU/HR (EACH)	0.026 LB/MMBTU	TURBINE DESIGN	0	BACT-OTHER
CIMARRON CHEMICAL	CO	Mar-91	TURBINE #2, GE FRAME 6	33 MW	250 T/YR, LESS THAN	CO CATALYST	0	OTHER
FLORIDA POWER AND LIGHT	FL	Mar-91	TURBINE, GAS, 4 EACH	240 MW	30 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
FLORIDA POWER AND LIGHT	FL	Mar-97	TURBINE, OIL, 4 EACH	0	33 PPM @ 15% O2	COMBUSTION CONTROL	0	BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	Jan-91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	40 LBS/HR	CATALYTIC CONVERTER	0	BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	Jan-91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	40 LBS/HR	CATALYTIC CONVERTER	0	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NJ	Nov-90	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	0.0055 LB/MMBTU	CATALYTIC OXIDATION	90	BACT-PSD
TBG COGEN COGENERATION PLANT	NY	Aug-90	GE LM2500 GAS TURBINE	315 MMBTU/HR	0.181 LB/MMBTU	CATALYTIC OXIDIZER	90	BACT
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	Dec-89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	23 LBS/HR	GOOD COMBUSTION PRACTICES	0	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	MA	Nov-89	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	40 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	0	BACT-OTHER
MEGAN-RACINE ASSOCIATES, INC	NY	Aug-89	GE LM5000-N COMBINED CYCLE GAS TURBINE	401 LB/MMBTU	0.026 LB/MMBTU, 11 LB/HR	NO CONTROLS	0	BACT-OTHER
UNOCAL	CA	Jul-89	TURBINE, GAS (SEE NOTES)	0	10 PPM @ 15% O2	OXIDATION CATALYST	75	BACT-OTHER

Note: PSD= Prevention of Significant Deterioration
BACT= Best Available Control Technology
LAER= Lowest Achievable Emission Rate

Table B-6. Direct and Indirect Capital Costs for CO Catalyst, General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$843,000	Vendor Quote
Flue Gas Ductwork	$66,758	Vatavauk, 1990
Instrumentation	$84,300	10% of SCR Associated Equipment
Sales Tax	$50,580	6% of SCR Associated Equipment/Catalyst
Freight	$42,150	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$1,086,788	
Direct Installation Costs		
Foundation and supports	$86,943	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$152,150	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$43,472	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$21,736	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$10,868	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$10,868	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$331,036	
Total Capital Costs	$1,417,824	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$141,782	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$70,891	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$141,782	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$28,356	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$14,178	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$42,535	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$439,526	
Total Direct, Indirect and Capital Costs (TDICC)	$1,857,350	Sum of TCC and TInCC

Table B-7. Annualized Cost for CO Catalyst, General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Diirect Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Catalyst Replacement	$214,333	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$28,365	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,496	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$257,371	
Energy Costs		
Heat Rate Penalty	$82,852	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$82,852	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$18,574	1% of Total Capital Costs
Insurance	$18,574	1% of Total Capital Costs
Annualized Total Direct Capital	$203,937	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$245,390	
Total Annualized Costs	$585,612	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$7,523	Simple CycleCombustion Turbine
	$9,869	Net Emission Reduction

ENGELHARD

Golder Assoc.
Westinghouse 501D and GE 7FA - Simple and Combined Cycle
CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

ENGELHARD CORPORATION
CAMET® CO OXIDATION SYSTEMS
NOxCAT SCR NOx ABATEMENT CATALYST SYSTEMS

Scope of Supply: The equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

- Engelhard **CAMET®** CO Oxidation Catalyst Modules;
- Engelhard **NOxCAT VNX™** (combined cycle) and **ZNX™** (simple cycle) SCR catalyst in modules;
- Internal support structures for catalyst modules (frame); includes all hardware and gaskets for catalyst module installation;
- Ambient Air injection cooling system components (simple cycle);
- Ammonia Injection Grid (AIG);
- AIG manifold with flow control valves ;
- NH_3/Air dilution skid: 28% Aqueous Ammonia
  - Pre-piped & wired (including all valves and fittings) Two (2) dilution air fans, one for back-up purposes
  - Panel mounted system controls for:
    - Blowers (on/off/flow indicators) Air/ammonia flow indicator and controller
    - System pressure indicators Main power disconnect switch

Excluded from Scope of Supply:
Ammonia storage and pumping
Any internally insulated reactor ductwork to house catalysts
Any transitions to and from reactor
Structural support
Any monorails and hoists for handling modules
Any interconnecting field piping or wiring
Electrical grounding equipment
Utilities
Foundations
All Monitors
All other items not specifically listed in Scope of Supply

BUDGET PRICES: **See Performance Data**

WARRANTY AND GUARANTEE:

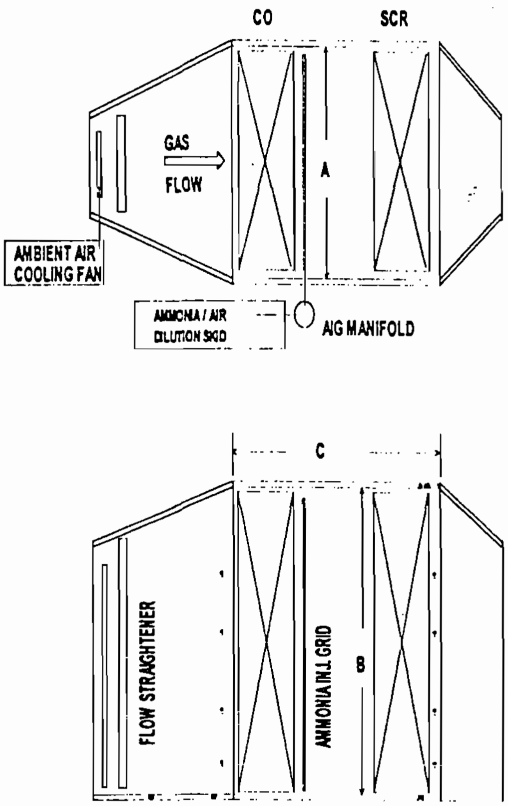
Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Simple cycle - 9,000 hours of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life
Performance Guarantee:	Combined cycle – 3 yearrs of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life

DOCUMENT / MATERIAL DELIVERY SCHEDULE
Drawings / Documentation - 10 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details
Operating manuals
Material Delivery 20 - 24 weeks after approval and release for fabrication

SYSTEM DESIGN BASIS:

Gas Flow from:	Westinghouse 501D and GE 7FA Combustion Turbines
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas and Oil
Gas Flow Rate (At catalyst face):	See Performance data
Temperature (At catalyst face):	See Performance data
CO Concentration (At catalyst face):	See Performance data
CO Reduction:	See Performance data
CO Pressure Drop:	See Performance data
NOx Concentration (At catalyst face):	See Performance data
NOx Reduction:	See Performance data
NH3 Slip:	9 and 5 ppmvd@15%O_2
Pressure Drop through SCR	Nom. 4"WG

<u>Dimensions / Sketch:</u> Simple Cycle
CO and SCR - w/ ambient cooling
Required Cross Sectional Area
Inside Liner Width x Inside Liner Height
(A x B) sq. ft.
Reactor Depth (C) 15'-0"



ENGELHARD

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Westinghouse 501D and GE 7FA - Simple and Combined Cycle
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December 13, 1999

GE 7FA – Simple Cycle

ASSUMED AMBIENT		59	59
GIVEN TURBINE EXHAUST TEMPERATURE, F		1,100	1,100
GIVEN TURBINE EXHAUST FLOW, lb/hr		3,900,000	4,080,000
ASSUMED TURBINE EXHAUST GAS ANALYSIS, % VOL.	N2	75.23	71.63
	O2	12.61	11.04
	CO2	3.63	5.20
	H2O	7.60	11.20
	Ar	0.93	0.93
AMBIENT AIR FLOW, lb/hr		332,949	348,316
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr		4,232,949	4,428,316
AMBIENT + EXHAUST GAS ANALYSIS, % VOL.	N2	75.70	72.37
	O2	13.09	11.64
	CO2	3.35	4.80
	H2O	7.01	10.33
	Ar	0.86	0.86
CALCULATED AIR + GAS MOL. WT.		28.48	28.32
GIVEN: TURBINE CO, ppmvd		9.0	20.0
CALC.: TURBINE CO, lb/hr		31.9	71.7
GIVEN: TURBINE NOx, ppmvd @ 15% O_2		9.0	42.0
CALC.: TURBINE NOx, lb/hr		64.5	355.2
CALC.: CO, ppmvd @ 15% O2 - AT CATALYST FACE		7.1	13.6
CALC.: NOx, ppmvd @ 15% O2 - AT CATALYST FACE		8.8	41.0
FLUE GAS TEMP. @ SCR CATALYST, F		1,025	1,025
DESIGN REQUIREMENTS			
CO CATALYST	CO CONVERSION, %	90%	90%
SCR CATALYST	NOx OUT, ppmvd @ 15% O2	3.5	ADVISE
	NH3 SLIP, ppmvd @ 15% O2	9	12
SCR PRESSURE DROP, 4.0"WG – Nom.			
GUARANTEED PERFORMANCE DATA			
	CO CONVERSION - % Min.	90.0%	90.0%
	CO OUT, ppmvd @ 15% O2	0.7	1.4
	CO OUT, lb/hr	3.2	7.2
	CO PRESSURE DROP	2.2	2.4
SCR CATALYST	NOx CONVERSION, % - Min.	61.1%	61.1%
	NOx OUT, lb/hr – Max.	25.1	138.1
	NOx OUT, ppmvd@15%O2 – Max.	3.4	16.0
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr		139	424
	NH3 SLIP, ppmvd@15%O2 – Max.	9	12
	SCR PRESSURE DROP, "WG - Max.	4.2	4.4
REQUIRED CROSS SECTION - INSIDE LINER - A x B, sq ft		**1650.0**	
CO SYSTEM		**$843,000**	
REPLACEMENT CO CATALYST MODULES		**$643,000**	
SCR SYSTEM		**$2,835,000**	
REPLACEMENT SCR CATALYST MODULES		**$1,479,000**	

APPENDIX C

BUILDING DOWNWASH INFORMATION FROM BPIP

```
'BPIP data for IPS Project, Desoto County Site'
'ST'
'FEET' 0.3048
'UTMN' 0
12
'N.Demin WTk' 1 0.0
8 50
400   200
364.6 185.4
350   150
364.6 114.6
400   100
435.4 114.6
450   150
435.4 185.4
'S.Demin Wtk' 1 0.0
8 50
400    80
364.6  65.4
350    30
364.6  -5.4
400   -20
435.4  -5.4
450    30
435.4  65.4
'W.FO Tk' 1 0.0
8 50
256   -214
220.6 -228.6
206   -264
220.6 -299.4
256   -314
291.4 -299.4
306   -264
291.4 -228.6
'E.FO Tk' 1 0.0
8 50
400   -214
364.6 -228.6
350   -264
364.6 -299.4
400   -314
435.4 -299.4
450   -264
435.4 -228.6
'InlFilt1' 1 0.0
4 47
-94 104
-94 140
-58 140
-58 104
'InlFilt2' 1 0.0
4 47
 22 104
 22 140
 58 140
 58 104
'InlFilt3' 1 0.0
4 47
138 104
138 140
174 140
174 104
'InlFilt4' 1 0.0
4 47
254 104
254 140
290 140
290 104
'Turb1' 1 0.0
4 22.
-131 34
-131 76
-101 76
-101 34
'Turb2' 1 0.0
4 22.
```

```
-15  34
-15  76
15   76
15   34
'Turb3' 1 0.0
4 22.
101  34
101  76
131  76
131  34
'Turb4' 1 0.0
4 22.
217  34
217  76
247  76
247  34
3
'CT1' 0.0 60 -116 0
'CT2' 0.0 60    0 0
'CT3' 0.0 60  116 0
0
```

BPIP (Dated: 95086)

DATE : 01/31/00
TIME : 17:28:54
BPIP data for IPS Project, Desoto County Site

============================
BPIP PROCESSING INFORMATION:
============================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in FEET will be converted to meters using a conversion factor of 0.3048. 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.

BPIP data for IPS Project, Desoto County Site

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
CT1	18.29	0.00	35.81	65.00
CT2	18.29	0.00	35.81	65.00
CT3	18.29	0.00	38.10	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 : 01/31/00
TIME : 17:28:54

BPIP data for IPS Project, Desoto County Site

BPIP output is in meters

SO BUILDHGT CT1	6.71	6.71	6.71	14.33	0.00	0.00
SO BUILDHGT CT1	0.00	0.00	0.00	0.00	0.00	0.00
SO BUILDHGT CT1	0.00	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT CT1	14.33	14.33	14.33	14.33	14.33	14.33
SO BUILDHGT CT1	6.71	6.71	0.00	0.00	0.00	0.00
SO BUILDHGT CT1	0.00	6.71	6.71	6.71	6.71	6.71
SO BUILDWID CT1	11.23	12.97	14.32	15.46	0.00	0.00
SO BUILDWID CT1	0.00	0.00	0.00	0.00	0.00	0.00
SO BUILDWID CT1	0.00	15.23	14.32	12.97	11.23	9.14
SO BUILDWID CT1	12.71	14.06	14.99	15.46	15.46	14.99
SO BUILDWID CT1	15.16	14.19	0.00	0.00	0.00	0.00
SO BUILDWID CT1	0.00	15.23	14.32	12.97	11.23	9.14

```
SO BUILDHGT CT2        6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT CT2        0.00    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT CT2       14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT CT2       14.33   14.33   14.33   14.33   14.33   14.33
SO BUILDHGT CT2        6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDHGT CT2        0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID CT2       11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID CT2        0.00    0.00    0.00   14.19   15.16   15.66
SO BUILDWID CT2       15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID CT2       12.71   14.06   14.99   15.46   15.46   14.99
SO BUILDWID CT2       15.16   14.19    0.00    0.00    0.00    0.00
SO BUILDWID CT2        0.00   15.23   14.32   12.97   11.23    9.14

SO BUILDHGT CT3        6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT CT3        0.00    0.00    0.00    6.71    6.71   14.33
SO BUILDHGT CT3       14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT CT3       14.33   14.33   14.33   14.33   15.24   15.24
SO BUILDHGT CT3       15.24   15.24   15.24    0.00    0.00    0.00
SO BUILDHGT CT3        0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID CT3       11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID CT3        0.00    0.00    0.00   14.19   15.16   14.99
SO BUILDWID CT3       15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID CT3       12.71   14.06   14.99   15.46   58.42   61.15
SO BUILDWID CT3       28.64   30.02   30.48    0.00    0.00    0.00
SO BUILDWID CT3        0.00   15.23   14.32   12.97   11.23    9.14
```

BPIP (Dated: 95086)

DATE : 01/31/00
TIME : 17:28:54
BPIP data for IPS Project, Desoto County Site

============================
BPIP PROCESSING INFORMATION:
============================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in FEET will be converted to meters using a conversion factor of 0.3048. 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.

==============
INPUT SUMMARY:
==============

Number of buildings to be processed : 12

N.Demin has 1 tier(s) with a base elevation of 0.00 FEET (0.00) meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER X	COORDINATES Y
N.Demin	1	1	50.00	8		
			15.24 meters			
					400.00	200.00 FEET
					121.92	60.96 meters
					364.60	185.40 FEET
					111.13	56.51 meters
					350.00	150.00 FEET
					106.68	45.72 meters
					364.60	114.60 FEET
					111.13	34.93 meters
					400.00	100.00 FEET
					121.92	30.48 meters
					435.40	114.60 FEET
					132.71	34.93 meters
					450.00	150.00 FEET
					137.16	45.72 meters
					435.40	185.40 FEET
					132.71	56.51 meters

S.Demin has 1 tier(s) with a base elevation of 0.00 FEET (0.00) meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER X	COORDINATES Y
S.Demin	1	5	50.00	8		
			15.24 meters			
					400.00	80.00 FEET
					121.92	24.38 meters
					364.60	65.40 FEET
					111.13	19.93 meters
					350.00	30.00 FEET
					106.68	9.14 meters
					364.60	-5.40 FEET
					111.13	-1.65 meters
					400.00	-20.00 FEET
					121.92	-6.10 meters
					435.40	-5.40 FEET
					132.71	-1.65 meters

450.00	30.00 FEET
137.16	9.14 meters
435.40	65.40 FEET
132.71	19.93 meters

W.FO Tk has 1 tier(s) with a base elevation of 0.00 FEET
(0.00) meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER X	COORDINATES Y
W.FO Tk	1	9	50.00	8		
			15.24 meters			
					256.00	-214.00 FEET
					78.03	-65.23 meters
					220.60	-228.60 FEET
					67.24	-69.68 meters
					206.00	-264.00 FEET
					62.79	-80.47 meters
					220.60	-299.40 FEET
					67.24	-91.26 meters
					256.00	-314.00 FEET
					78.03	-95.71 meters
					291.40	-299.40 FEET
					88.82	-91.26 meters
					306.00	-264.00 FEET
					93.27	-80.47 meters
					291.40	-228.60 FEET
					88.82	-69.68 meters

E.FO Tk has 1 tier(s) with a base elevation of 0.00 FEET
(0.00) meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER X	COORDINATES Y
E.FO Tk	1	13	50.00	8		
			15.24 meters			
					400.00	-214.00 FEET
					121.92	-65.23 meters
					364.60	-228.60 FEET
					111.13	-69.68 meters
					350.00	-264.00 FEET
					106.68	-80.47 meters
					364.60	-299.40 FEET
					111.13	-91.26 meters
					400.00	-314.00 FEET
					121.92	-95.71 meters
					435.40	-299.40 FEET
					132.71	-91.26 meters
					450.00	-264.00 FEET
					137.16	-80.47 meters
					435.40	-228.60 FEET
					132.71	-69.68 meters

InlFilt1 has 1 tier(s) with a base elevation of 0.00 FEET
(0.00) meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER X	COORDINATES Y
InlFilt1	1	17	47.00	4		
			14.33 meters			
					-94.00	104.00 FEET
					-28.65	31.70 meters
					-94.00	140.00 FEET
					-28.65	42.67 meters
					-58.00	140.00 FEET
					-17.68	42.67 meters
					-58.00	104.00 FEET
					-17.68	31.70 meters

InlFilt2 has 1 tier(s) with a base elevation of 0.00 FEET

```
                                                    (     0.00) meters

BUILDING  TIER  BLDG-TIER  TIER   NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

InlFilt2    1        21    47.00     4
                           14.33 meters
                                                    22.00       104.00 FEET
                                                     6.71        31.70 meters
                                                    22.00       140.00 FEET
                                                     6.71        42.67 meters
                                                    58.00       140.00 FEET
                                                    17.68        42.67 meters
                                                    58.00       104.00 FEET
                                                    17.68        31.70 meters


InlFilt3 has 1 tier(s) with a base elevation of     0.00 FEET
                                                    (     0.00) meters

BUILDING  TIER  BLDG-TIER  TIER   NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

InlFilt3    1        25    47.00     4
                           14.33 meters
                                                   138.00       104.00 FEET
                                                    42.06        31.70 meters
                                                   138.00       140.00 FEET
                                                    42.06        42.67 meters
                                                   174.00       140.00 FEET
                                                    53.04        42.67 meters
                                                   174.00       104.00 FEET
                                                    53.04        31.70 meters


InlFilt4 has 1 tier(s) with a base elevation of     0.00 FEET
                                                    (     0.00) meters

BUILDING  TIER  BLDG-TIER  TIER   NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

InlFilt4    1        29    47.00     4
                           14.33 meters
                                                   254.00       104.00 FEET
                                                    77.42        31.70 meters
                                                   254.00       140.00 FEET
                                                    77.42        42.67 meters
                                                   290.00       140.00 FEET
                                                    88.39        42.67 meters
                                                   290.00       104.00 FEET
                                                    88.39        31.70 meters


Turb1     has 1 tier(s) with a base elevation of    0.00 FEET
                                                    (     0.00) meters

BUILDING  TIER  BLDG-TIER  TIER   NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

Turb1       1        33    22.00     4
                            6.71 meters
                                                  -131.00        34.00 FEET
                                                   -39.93        10.36 meters
                                                  -131.00        76.00 FEET
                                                   -39.93        23.16 meters
                                                  -101.00        76.00 FEET
                                                   -30.78        23.16 meters
                                                  -101.00        34.00 FEET
                                                   -30.78        10.36 meters


Turb2     has 1 tier(s) with a base elevation of    0.00 FEET
                                                    (     0.00) meters

BUILDING  TIER  BLDG-TIER  TIER   NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y
```

```
Turb2        1        37      22.00      4
                               6.71 meters
                                                   -15.00        34.00 FEET
                                                    -4.57        10.36 meters
                                                   -15.00        76.00 FEET
                                                    -4.57        23.16 meters
                                                    15.00        76.00 FEET
                                                     4.57        23.16 meters
                                                    15.00        34.00 FEET
                                                     4.57        10.36 meters


Turb3    has 1 tier(s) with a base elevation of    0.00 FEET
                                                (    0.00) meters

BUILDING  TIER  BLDG-TIER  TIER    NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

Turb3        1        41      22.00      4
                               6.71 meters
                                                   101.00        34.00 FEET
                                                    30.78        10.36 meters
                                                   101.00        76.00 FEET
                                                    30.78        23.16 meters
                                                   131.00        76.00 FEET
                                                    39.93        23.16 meters
                                                   131.00        34.00 FEET
                                                    39.93        10.36 meters


Turb4    has 1 tier(s) with a base elevation of    0.00 FEET
                                                (    0.00) meters

BUILDING  TIER  BLDG-TIER  TIER    NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

Turb4        1        45      22.00      4
                               6.71 meters
                                                   217.00        34.00 FEET
                                                    66.14        10.36 meters
                                                   217.00        76.00 FEET
                                                    66.14        23.16 meters
                                                   247.00        76.00 FEET
                                                    75.29        23.16 meters
                                                   247.00        34.00 FEET
                                                    75.29        10.36 meters

Number of stacks to be processed :    3

                      STACK              STACK    COORDINATES
 STACK NAME       BASE  HEIGHT             X             Y

 CT1              0.00   60.00 FEET
             (    0.00   18.29) meters
                                       -116.00        0.00 FEET
                              (         -35.36        0.00) meters
 CT2              0.00   60.00 FEET
             (    0.00   18.29) meters
                                          0.00        0.00 FEET
                              (           0.00        0.00) meters
 CT3              0.00   60.00 FEET
             (    0.00   18.29) meters
                                        116.00        0.00 FEET
                              (          35.36        0.00) meters

   No stacks have been detected as being atop any structures.


                    Overall GEP Summary Table
                         (Units: meters)


StkNo:   1  Stk Name:CT1       Stk Ht:  18.29 Prelim. GEP Stk.Ht:    65.00
           GEP:  BH:  14.33  PBW:    14.34             *Eqn1 Ht:    35.81
         *adjusted for a Stack-Building elevation difference of     0.00
 No. of Tiers affecting Stk:  1  Direction occurred:  202.50
  Bldg-Tier nos. contributing to GEP:  17
```

```
StkNo:  2  Stk Name:CT2      Stk Ht:  18.29 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  14.33  PBW:   14.34            *Eqn1 Ht:   35.81
        *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:  202.50
  Bldg-Tier nos. contributing to GEP:  21


StkNo:  3  Stk Name:CT3      Stk Ht:  18.29 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  15.24  PBW:   29.76            *Eqn1 Ht:   38.10
        *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:  257.50
  Bldg-Tier nos. contributing to GEP:   5
```

Summary By Direction Table
(Units: meters)

```
Dominate stand alone tiers:


Drtcn:  10.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  11.23  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  9  Bld Name:Turb1     TierNo:  1
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  11.23  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 10  Bld Name:Turb2     TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
    Single tier MAX:  BH:   6.71  PBW:  11.23  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 11  Bld Name:Turb3     TierNo:  1

Drtcn:  20.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  12.97  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  9  Bld Name:Turb1     TierNo:  1
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  12.97  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 10  Bld Name:Turb2     TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
    Single tier MAX:  BH:   6.71  PBW:  12.97  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 11  Bld Name:Turb3     TierNo:  1

Drtcn:  30.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  14.32  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  9  Bld Name:Turb1     TierNo:  1
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  14.32  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 10  Bld Name:Turb2     TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
    Single tier MAX:  BH:   6.71  PBW:  14.32  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 11  Bld Name:Turb3     TierNo:  1
```

```
Drtcn:  40.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  5  Bld Name:InlFilt1  TierNo:  1
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  6  Bld Name:InlFilt2  TierNo:  1
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  7  Bld Name:InlFilt3  TierNo:  1

Drtcn:  50.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    No single tier affects this stack for this direction.

Drtcn:  60.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    No single tier affects this stack for this direction.

Drtcn:  70.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    No single tier affects this stack for this direction.

Drtcn:  80.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    No single tier affects this stack for this direction.

Drtcn:  90.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
```

```
    No single tier affects this stack for this direction.

Drtcn: 100.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  14.19  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  9  Bld Name:Turb1     TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:   6.71  PBW:  14.19  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo: 10  Bld Name:Turb2     TierNo:  1

Drtcn: 110.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  15.16  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  9  Bld Name:Turb1     TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:   6.71  PBW:  15.16  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo: 10  Bld Name:Turb2     TierNo:  1

Drtcn: 120.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  15.66  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  9  Bld Name:Turb1     TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  14.33  PBW:  14.99  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  5  Bld Name:InlFilt1  TierNo:  1

Drtcn: 130.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  5  Bld Name:InlFilt1  TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  6  Bld Name:InlFilt2  TierNo:  1

Drtcn: 140.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  15.23  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  9  Bld Name:Turb1     TierNo:  1
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
```

```
                BldNo:  5  Bld Name:InlFilt1   TierNo:  1
StkNo:  3  Stk Name:CT3                               Stack Ht:    18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:    38.10
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo:  6  Bld Name:InlFilt2   TierNo:  1

Drtcn: 150.00

StkNo:  1  Stk Name:CT1                               Stack Ht:    18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:    35.81
    Single tier MAX:  BH:   6.71  PBW:  14.32  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo:  9  Bld Name:Turb1      TierNo:  1
StkNo:  2  Stk Name:CT2                               Stack Ht:    18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:    35.81
    Single tier MAX:  BH:  14.33  PBW:  14.99  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo:  5  Bld Name:InlFilt1   TierNo:  1
StkNo:  3  Stk Name:CT3                               Stack Ht:    18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:    38.10
    Single tier MAX:  BH:  14.33  PBW:  14.99  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo:  6  Bld Name:InlFilt2   TierNo:  1

Drtcn: 160.00

StkNo:  1  Stk Name:CT1                               Stack Ht:    18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:    35.81
    Single tier MAX:  BH:   6.71  PBW:  12.97  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo:  9  Bld Name:Turb1      TierNo:  1
StkNo:  2  Stk Name:CT2                               Stack Ht:    18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:    35.81
    Single tier MAX:  BH:  14.33  PBW:  14.06  *Wake Effect Ht:   35.42
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo:  5  Bld Name:InlFilt1   TierNo:  1
StkNo:  3  Stk Name:CT3                               Stack Ht:    18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:    38.10
    Single tier MAX:  BH:  14.33  PBW:  14.06  *Wake Effect Ht:   35.42
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo:  6  Bld Name:InlFilt2   TierNo:  1

Drtcn: 170.00

StkNo:  1  Stk Name:CT1                               Stack Ht:    18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:    35.81
    Single tier MAX:  BH:   6.71  PBW:  11.23  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo:  9  Bld Name:Turb1      TierNo:  1
StkNo:  2  Stk Name:CT2                               Stack Ht:    18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:    35.81
    Single tier MAX:  BH:   6.71  PBW:  11.23  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo: 10  Bld Name:Turb2      TierNo:  1
StkNo:  3  Stk Name:CT3                               Stack Ht:    18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:    38.10
    Single tier MAX:  BH:   6.71  PBW:  11.23  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo: 11  Bld Name:Turb3      TierNo:  1

Drtcn: 180.00

StkNo:  1  Stk Name:CT1                               Stack Ht:    18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:    35.81
    Single tier MAX:  BH:   6.71  PBW:   9.14  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo:  9  Bld Name:Turb1      TierNo:  1
StkNo:  2  Stk Name:CT2                               Stack Ht:    18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:    35.81
    Single tier MAX:  BH:   6.71  PBW:   9.14  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
                BldNo: 10  Bld Name:Turb2      TierNo:  1
StkNo:  3  Stk Name:CT3                               Stack Ht:    18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:    38.10
    Single tier MAX:  BH:   6.71  PBW:   9.14  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
```

```
              BldNo: 11  Bld Name:Turb3     TierNo:  1

Drtcn: 190.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  12.71  *Wake Effect Ht:   33.39
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  5  Bld Name:InlFilt1  TierNo:  1
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  12.71  *Wake Effect Ht:   33.39
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  6  Bld Name:InlFilt2  TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  14.33  PBW:  12.71  *Wake Effect Ht:   33.39
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  7  Bld Name:InlFilt3  TierNo:  1

Drtcn: 200.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  14.06  *Wake Effect Ht:   35.42
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  5  Bld Name:InlFilt1  TierNo:  1
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  14.06  *Wake Effect Ht:   35.42
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  6  Bld Name:InlFilt2  TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  14.33  PBW:  14.06  *Wake Effect Ht:   35.42
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  7  Bld Name:InlFilt3  TierNo:  1

Drtcn: 210.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  14.99  *Wake Effect Ht:   35.81
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  5  Bld Name:InlFilt1  TierNo:  1
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  14.99  *Wake Effect Ht:   35.81
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  6  Bld Name:InlFilt2  TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  14.33  PBW:  14.99  *Wake Effect Ht:   35.81
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  7  Bld Name:InlFilt3  TierNo:  1

Drtcn: 220.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  5  Bld Name:InlFilt1  TierNo:  1
StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  6  Bld Name:InlFilt2  TierNo:  1
StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  8  Bld Name:InlFilt4  TierNo:  1

Drtcn: 230.00

StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
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                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  6  Bld Name:InlFilt2  TierNo:  1
StkNo:  2  Stk Name:CT2                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  7  Bld Name:InlFilt3  TierNo:  1
StkNo:  3  Stk Name:CT3                                Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  14.33  PBW:  15.46  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  8  Bld Name:InlFilt4  TierNo:  1

Drtcn: 240.00

StkNo:  1  Stk Name:CT1                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  14.99  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  6  Bld Name:InlFilt2  TierNo:  1
StkNo:  2  Stk Name:CT2                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:  14.33  PBW:  14.99  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  7  Bld Name:InlFilt3  TierNo:  1
StkNo:  3  Stk Name:CT3                                Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  14.33  PBW:  14.99  *Wake Effect Ht:   35.81
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  8  Bld Name:InlFilt4  TierNo:  1

Drtcn: 250.00

StkNo:  1  Stk Name:CT1                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  15.16  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo: 10  Bld Name:Turb2     TierNo:  1
StkNo:  2  Stk Name:CT2                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  15.16  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo: 11  Bld Name:Turb3     TierNo:  1
StkNo:  3  Stk Name:CT3                                Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  15.24  PBW:  28.64  *Wake Effect Ht:   38.10
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  2  Bld Name:S.Demin   TierNo:  1

Drtcn: 260.00

StkNo:  1  Stk Name:CT1                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  14.19  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo: 10  Bld Name:Turb2     TierNo:  1
StkNo:  2  Stk Name:CT2                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  14.19  *Wake Effect Ht:   16.76
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo: 11  Bld Name:Turb3     TierNo:  1
StkNo:  3  Stk Name:CT3                                Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  15.24  PBW:  30.02  *Wake Effect Ht:   38.10
         *adjusted for a Stack-Building elevation difference of    0.00
               BldNo:  2  Bld Name:S.Demin   TierNo:  1

Drtcn: 270.00

StkNo:  1  Stk Name:CT1                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
```

```
StkNo:  3  Stk Name:CT3                                Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
    Single tier MAX:  BH:  15.24  PBW:  30.48  *Wake Effect Ht:  38.10
         *adjusted for a Stack-Building elevation difference of   0.00
               BldNo:  2  Bld Name:S.Demin    TierNo:  1

Drtcn: 280.00

StkNo:  1  Stk Name:CT1                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  3  Stk Name:CT3                                Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
    No single tier affects this stack for this direction.

Drtcn: 290.00

StkNo:  1  Stk Name:CT1                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  3  Stk Name:CT3                                Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
    No single tier affects this stack for this direction.

Drtcn: 300.00

StkNo:  1  Stk Name:CT1                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  3  Stk Name:CT3                                Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
    No single tier affects this stack for this direction.

Drtcn: 310.00

StkNo:  1  Stk Name:CT1                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  2  Stk Name:CT2                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    No single tier affects this stack for this direction.
StkNo:  3  Stk Name:CT3                                Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
    No single tier affects this stack for this direction.

Drtcn: 320.00

StkNo:  1  Stk Name:CT1                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  15.23  *Wake Effect Ht:  16.76
         *adjusted for a Stack-Building elevation difference of   0.00
               BldNo:  9  Bld Name:Turb1      TierNo:  1
StkNo:  2  Stk Name:CT2                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  15.23  *Wake Effect Ht:  16.76
         *adjusted for a Stack-Building elevation difference of   0.00
               BldNo: 10  Bld Name:Turb2      TierNo:  1
StkNo:  3  Stk Name:CT3                                Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
    Single tier MAX:  BH:   6.71  PBW:  15.23  *Wake Effect Ht:  16.76
         *adjusted for a Stack-Building elevation difference of   0.00
               BldNo: 11  Bld Name:Turb3      TierNo:  1

Drtcn: 330.00

StkNo:  1  Stk Name:CT1                                Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
    Single tier MAX:  BH:   6.71  PBW:  14.32  *Wake Effect Ht:  16.76
```

```
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  9  Bld Name:Turb1      TierNo:  1
 StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     Single tier MAX:  BH:   6.71  PBW:  14.32  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 10  Bld Name:Turb2      TierNo:  1
 StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
     Single tier MAX:  BH:   6.71  PBW:  14.32  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 11  Bld Name:Turb3      TierNo:  1

 Drtcn: 340.00

 StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     Single tier MAX:  BH:   6.71  PBW:  12.97  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  9  Bld Name:Turb1      TierNo:  1
 StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     Single tier MAX:  BH:   6.71  PBW:  12.97  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 10  Bld Name:Turb2      TierNo:  1
 StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
     Single tier MAX:  BH:   6.71  PBW:  12.97  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 11  Bld Name:Turb3      TierNo:  1

 Drtcn: 350.00

 StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     Single tier MAX:  BH:   6.71  PBW:  11.23  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  9  Bld Name:Turb1      TierNo:  1
 StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     Single tier MAX:  BH:   6.71  PBW:  11.23  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 10  Bld Name:Turb2      TierNo:  1
 StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
     Single tier MAX:  BH:   6.71  PBW:  11.23  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 11  Bld Name:Turb3      TierNo:  1

 Drtcn: 360.00

 StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     Single tier MAX:  BH:   6.71  PBW:   9.14  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo:  9  Bld Name:Turb1      TierNo:  1
 StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     Single tier MAX:  BH:   6.71  PBW:   9.14  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 10  Bld Name:Turb2      TierNo:  1
 StkNo:  3  Stk Name:CT3                              Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
     Single tier MAX:  BH:   6.71  PBW:   9.14  *Wake Effect Ht:   16.76
        *adjusted for a Stack-Building elevation difference of    0.00
              BldNo: 11  Bld Name:Turb3      TierNo:  1


Dominate combined buildings:

 Drtcn:  10.00

 StkNo:  1  Stk Name:CT1                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
      No combined tiers affect this stack for this direction.
 StkNo:  2  Stk Name:CT2                              Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
```

```
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
               GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn:  20.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
               GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn:  30.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
               GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn:  40.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
               GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn:  50.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
               GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn:  60.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
               GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn:  70.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
               GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
               GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.
```

```
Drtcn:  80.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn:  90.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 100.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 110.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 120.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 130.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                  Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 140.00

StkNo:  1  Stk Name:CT1                                  Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
```

```
StkNo:  2  Stk Name:CT2                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                 Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 150.00

StkNo:  1  Stk Name:CT1                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                 Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 160.00

StkNo:  1  Stk Name:CT1                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                 Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 170.00

StkNo:  1  Stk Name:CT1                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                 Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 180.00

StkNo:  1  Stk Name:CT1                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                 Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 190.00

StkNo:  1  Stk Name:CT1                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                 Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 200.00

StkNo:  1  Stk Name:CT1                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                 Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                 Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
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```
     No combined tiers affect this stack for this direction.

Drtcn: 210.00

StkNo:  1  Stk Name:CT1                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                               Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 220.00

StkNo:  1  Stk Name:CT1                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                               Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction.

Drtcn: 230.00

StkNo:  1  Stk Name:CT1                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                               Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
  Combined tier MAX:  BH:  15.24  PBW:  58.42  *Wake Effect Ht:   38.10
       *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  2
  Bldg-Tier nos. contributing to MAX:   1   5

Drtcn: 240.00

StkNo:  1  Stk Name:CT1                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                               Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
  Combined tier MAX:  BH:  15.24  PBW:  61.15  *Wake Effect Ht:   38.10
       *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  2
  Bldg-Tier nos. contributing to MAX:   1   5

Drtcn: 250.00

StkNo:  1  Stk Name:CT1                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                               Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
  Combined tier MAX:  BH:  15.24  PBW:  63.01  *Wake Effect Ht:   38.10
       *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  2
  Bldg-Tier nos. contributing to MAX:   1   5

Drtcn: 260.00

StkNo:  1  Stk Name:CT1                               Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                               Stack Ht:   18.29
```

```
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
  Combined tier MAX:  BH:  15.24  PBW:  66.04  *Wake Effect Ht:   38.10
       *adjusted for a Stack-Building elevation difference of     0.00
 No. of Tiers affecting Stk:  2
  Bldg-Tier nos. contributing to MAX:   1   5

Drtcn: 270.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
  Combined tier MAX:  BH:  15.24  PBW:  67.06  *Wake Effect Ht:   38.10
       *adjusted for a Stack-Building elevation difference of     0.00
 No. of Tiers affecting Stk:  2
  Bldg-Tier nos. contributing to MAX:   1   5

Drtcn: 280.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction

Drtcn: 290.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction

Drtcn: 300.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction

Drtcn: 310.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                             Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76   *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction

Drtcn: 320.00

StkNo:  1  Stk Name:CT1                             Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34   *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
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StkNo:  2  Stk Name:CT2                                   Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                   Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction

Drtcn: 330.00

StkNo:  1  Stk Name:CT1                                   Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                   Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                   Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction

Drtcn: 340.00

StkNo:  1  Stk Name:CT1                                   Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                   Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                   Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction

Drtcn: 350.00

StkNo:  1  Stk Name:CT1                                   Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                   Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                   Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction

Drtcn: 360.00

StkNo:  1  Stk Name:CT1                                   Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  2  Stk Name:CT2                                   Stack Ht:   18.29
                GEP:  BH:  14.33  PBW:  14.34  *Equation 1 Ht:   35.81
     No combined tiers affect this stack for this direction.
StkNo:  3  Stk Name:CT3                                   Stack Ht:   18.29
                GEP:  BH:  15.24  PBW:  29.76  *Equation 1 Ht:   38.10
     No combined tiers affect this stack for this direction
```

APPENDIX D

DETAILED SUMMARY OF ISCST MODEL RESULTS

ISCBOB3 RELEASE 98056

ISCST3 OUTPUT FILE NUMBER 1 :GENNG.087
ISCST3 OUTPUT FILE NUMBER 2 :GENNG.088
ISCST3 OUTPUT FILE NUMBER 3 :GENNG.089
ISCST3 OUTPUT FILE NUMBER 4 :GENNG.090
ISCST3 OUTPUT FILE NUMBER 5 :GENNG.091
First title for last output file is: 1987 IPS DESOTO COUNTY SITE 1/22/00
Second title for last output file is: NATURAL GAS, GENERIC EMISSION RATES, 3 LOADS AND 2 TEMPERATURES

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BASE32				
Annual					
	1987	0.01073	200.	15000.	87123124
	1988	0.01249	240.	15000.	88123124
	1989	0.01013	230.	15000.	89123124
	1990	0.01878	240.	15000.	90123124
	1991	0.01294	230.	15000.	91123124
HIGH 24-Hour					
	1987	0.25006	250.	10000.	87081824
	1988	0.21167	180.	20000.	88121824
	1989	0.13373	140.	20000.	89012324
	1990	0.15682	250.	25000.	90011824
	1991	0.16003	250.	20000.	91111424
HIGH 8-Hour					
	1987	0.41389	250.	20000.	87081808
	1988	0.42329	180.	20000.	88121808
	1989	0.37149	140.	20000.	89012308
	1990	0.45590	300.	20000.	90022208
	1991	0.41409	250.	20000.	91113008
HIGH 3-Hour					
	1987	0.79236	210.	20000.	87110706
	1988	0.80750	260.	20000.	88091703
	1989	0.63932	270.	20000.	89092924
	1990	0.88122	190.	2000.	90041815
	1991	0.85125	180.	2000.	91081615
HIGH 1-Hour					
	1987	1.79989	330.	1500.	87082013
	1988	1.68363	180.	1500.	88070313
	1989	1.76711	140.	1500.	89052811
	1990	1.72549	180.	1500.	90082913
	1991	1.71547	250.	1500.	91090713
SOURCE GROUP ID:	BASE95				
Annual					
	1987	0.00958	200.	20000.	87123124
	1988	0.01121	240.	15000.	88123124
	1989	0.00915	240.	15000.	89123124
	1990	0.01714	240.	15000.	90123124
	1991	0.01150	230.	15000.	91123124
HIGH 24-Hour					
	1987	0.23906	250.	10000.	87081824
	1988	0.19623	180.	20000.	88121824
	1989	0.12421	310.	20000.	89091224
	1990	0.14501	190.	2000.	90041824
	1991	0.13044	250.	20000.	91113024
HIGH 8-Hour					
	1987	0.39409	250.	7000.	87081816
	1988	0.39396	180.	20000.	88121808
	1989	0.34162	140.	20000.	89012308
	1990	0.42153	300.	20000.	90022208
	1991	0.38073	250.	20000.	91113008
HIGH 3-Hour					
	1987	0.73708	210.	20000.	87110706
	1988	0.74575	260.	20000.	88091703
	1989	0.58847	270.	20000.	89092924
	1990	0.87009	190.	2000.	90041815
	1991	0.64999	250.	20000.	91111424
HIGH 1-Hour					
	1987	1.57755	300.	2000.	87081713
	1988	1.55693	100.	2000.	88080613
	1989	1.61905	270.	2000.	89052013
	1990	1.58331	120.	2000.	90032713
	1991	1.60285	210.	2000.	91092013
SOURCE GROUP ID:	LD7532				

Annual					
	1987	0.01248	200.	15000.	87123124
	1988	0.01448	240.	15000.	88123124
	1989	0.01186	230.	15000.	89123124
	1990	0.02156	240.	15000.	90123124
	1991	0.01560	230.	15000.	91123124
HIGH 24-Hour					
	1987	0.27106	250.	10000.	87081824
	1988	0.24077	180.	20000.	88121824
	1989	0.15501	140.	20000.	89012324
	1990	0.19314	230.	7000.	90051124
	1991	0.22477	60.	5000.	91070224
HIGH 8-Hour					
	1987	0.47962	250.	20000.	87081808
	1988	0.47797	180.	20000.	88121808
	1989	0.42824	140.	20000.	89012308
	1990	0.51927	300.	20000.	90022208
	1991	0.47696	60.	5000.	91070216
HIGH 3-Hour					
	1987	0.89392	210.	15000.	87110706
	1988	0.92078	260.	20000.	88091703
	1989	0.73319	270.	20000.	89092924
	1990	0.89978	190.	2000.	90041815
	1991	0.86279	180.	2000.	91081615
HIGH 1-Hour					
	1987	2.12903	160.	1500.	87080314
	1988	2.11029	230.	1500.	88081714
	1989	2.11303	40.	1500.	89061114
	1990	1.94602	50.	1500.	90062013
	1991	2.07769	60.	1500.	91041513
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.01311	250.	10000.	87123124
	1988	0.01494	240.	15000.	88123124
	1989	0.01261	300.	12000.	89123124
	1990	0.02229	240.	15000.	90123124
	1991	0.01638	230.	15000.	91123124
HIGH 24-Hour					
	1987	0.32191	250.	7000.	87081824
	1988	0.25135	180.	20000.	88121824
	1989	0.18118	310.	12000.	89091224
	1990	0.19655	230.	7000.	90051124
	1991	0.22594	60.	5000.	91070224
HIGH 8-Hour					
	1987	0.54471	250.	7000.	87081816
	1988	0.49927	180.	15000.	88121808
	1989	0.44914	140.	20000.	89012308
	1990	0.54231	300.	20000.	90022208
	1991	0.49962	250.	20000.	91113008
HIGH 3-Hour					
	1987	0.88647	190.	20000.	87100506
	1988	0.96202	260.	20000.	88091703
	1989	0.76758	270.	20000.	89092924
	1990	0.90609	190.	2000.	90041815
	1991	0.86936	250.	20000.	91111424
HIGH 1-Hour					
	1987	2.22672	270.	1500.	87052012
	1988	2.12673	230.	1500.	88081714
	1989	2.23785	270.	1500.	89060211
	1990	2.21722	180.	1500.	90090912
	1991	2.19288	210.	1500.	91072614
SOURCE GROUP ID:	LD5032				
Annual					
	1987	0.01473	230.	15000.	87123124
	1988	0.01696	240.	15000.	88123124
	1989	0.01528	300.	10000.	89123124
	1990	0.02576	240.	15000.	90123124
	1991	0.01919	250.	12000.	91123124
HIGH 24-Hour					
	1987	0.34748	250.	7000.	87081824
	1988	0.28350	180.	15000.	88121824
	1989	0.20507	310.	12000.	89091224
	1990	0.23754	240.	15000.	90121424
	1991	0.25555	170.	1500.	91081624
HIGH 8-Hour					
	1987	0.57150	250.	20000.	87081808
	1988	0.56001	180.	15000.	88121808

	1989	0.50596	140.	20000.	89012308
	1990	0.60461	300.	20000.	90022208
	1991	0.65713	170.	1500.	91081616
HIGH 3-Hour					
	1987	0.98871	190.	20000.	87100506
	1988	1.05546	260.	20000.	88091703
	1989	0.86172	270.	20000.	89092924
	1990	1.38962	50.	1500.	90090812
	1991	0.98784	250.	20000.	91111424
HIGH 1-Hour					
	1987	2.52862	20.	1500.	87092013
	1988	2.50968	230.	1500.	88080912
	1989	2.49061	50.	1500.	89072812
	1990	2.46930	50.	1500.	90090811
	1991	2.49642	300.	1500.	91090112
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.01517	250.	10000.	87123124
	1988	0.01740	240.	15000.	88123124
	1989	0.01587	300.	10000.	89123124
	1990	0.02624	240.	15000.	90123124
	1991	0.01981	250.	12000.	91123124
HIGH 24-Hour					
	1987	0.35444	250.	7000.	87081824
	1988	0.29328	180.	15000.	88121824
	1989	0.21226	310.	12000.	89091224
	1990	0.22838	240.	15000.	90121424
	1991	0.25846	170.	1500.	91081624
HIGH 8-Hour					
	1987	0.59172	250.	20000.	87081808
	1988	0.57851	180.	15000.	88121808
	1989	0.52325	140.	20000.	89012308
	1990	0.62310	300.	20000.	90022208
	1991	0.66461	170.	1500.	91081616
HIGH 3-Hour					
	1987	1.01921	190.	20000.	87100506
	1988	1.08929	260.	20000.	88091703
	1989	0.88980	180.	1500.	89061115
	1990	1.39654	50.	1500.	90090812
	1991	1.02368	250.	20000.	91111424
HIGH 1-Hour					
	1987	2.62624	20.	1500.	87092113
	1988	2.65961	10.	1500.	88081713
	1989	2.66940	180.	1500.	89061113
	1990	2.62153	80.	1500.	90082212
	1991	2.61038	270.	1500.	91062812

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB3 RELEASE 98056

ISCST3 OUTPUT FILE NUMBER 1 :GENFO.087
ISCST3 OUTPUT FILE NUMBER 2 :GENFO.088
ISCST3 OUTPUT FILE NUMBER 3 :GENFO.089
ISCST3 OUTPUT FILE NUMBER 4 :GENFO.090
ISCST3 OUTPUT FILE NUMBER 5 :GENFO.091
First title for last output file is: 1987 IPS DESOTO COUNTY SITE 1/22/00
Second title for last output file is: FUEL OIL, GENERIC EMISSION RATES, 3 LOADS AND 2 TEMPERATURES

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BASE32				
Annual					
	1987	0.01039	200.	20000.	87123124
	1988	0.01222	240.	15000.	88123124
	1989	0.00984	230.	15000.	89123124
	1990	0.01830	240.	15000.	90123124
	1991	0.01256	250.	15000.	91123124
HIGH 24-Hour					
	1987	0.24690	250.	10000.	87081824
	1988	0.20707	180.	20000.	88121824
	1989	0.13095	310.	20000.	89091224
	1990	0.15264	250.	25000.	90011824
	1991	0.14155	180.	2000.	91081624
HIGH 8-Hour					
	1987	0.40379	250.	20000.	87081808
	1988	0.41456	180.	20000.	88121808
	1989	0.36264	140.	20000.	89012308
	1990	0.44596	300.	20000.	90022208
	1991	0.40442	250.	20000.	91113008
HIGH 3-Hour					
	1987	0.77633	210.	20000.	87110706
	1988	0.78981	260.	20000.	88091703
	1989	0.62475	270.	20000.	89092924
	1990	0.87814	190.	2000.	90041815
	1991	0.84932	180.	2000.	91081615
HIGH 1-Hour					
	1987	1.66213	230.	1500.	87083014
	1988	1.67805	180.	1500.	88070313
	1989	1.63472	270.	2000.	89052013
	1990	1.71504	330.	1500.	90091413
	1991	1.70927	250.	1500.	91090713
SOURCE GROUP ID:	BASE95				
Annual					
	1987	0.01102	200.	15000.	87123124
	1988	0.01274	240.	15000.	88123124
	1989	0.01036	230.	15000.	89123124
	1990	0.01922	240.	15000.	90123124
	1991	0.01346	250.	15000.	91123124
HIGH 24-Hour					
	1987	0.25333	250.	10000.	87081824
	1988	0.21638	180.	20000.	88121824
	1989	0.13713	140.	20000.	89012324
	1990	0.16114	250.	25000.	90011824
	1991	0.16309	250.	20000.	91111424
HIGH 8-Hour					
	1987	0.42426	250.	20000.	87081808
	1988	0.43222	180.	20000.	88121808
	1989	0.38058	140.	20000.	89012308
	1990	0.46606	300.	20000.	90022208
	1991	0.42402	250.	20000.	91113008
HIGH 3-Hour					
	1987	0.80872	210.	20000.	87110706
	1988	0.82559	260.	20000.	88091703
	1989	0.65424	270.	20000.	89092924
	1990	0.88430	190.	2000.	90041815
	1991	0.85317	180.	2000.	91081615
HIGH 1-Hour					
	1987	1.81643	270.	1500.	87062113
	1988	1.68994	180.	1500.	88070313
	1989	1.80207	50.	1500.	89060312
	1990	1.85703	90.	1500.	90081014
	1991	1.79104	80.	1500.	91041014
SOURCE GROUP ID:	LD7532				

Annual					
	1987	0.01242	200.	15000.	87123124
	1988	0.01439	240.	15000.	88123124
	1989	0.01175	230.	15000.	89123124
	1990	0.02133	240.	15000.	90123124
	1991	0.01553	230.	15000.	91123124
HIGH 24-Hour					
	1987	0.27029	250.	10000.	87081824
	1988	0.23974	180.	20000.	88121824
	1989	0.15425	140.	20000.	89012324
	1990	0.19275	230.	7000.	90051124
	1991	0.22470	60.	5000.	91070224
HIGH 8-Hour					
	1987	0.47725	250.	20000.	87081808
	1988	0.47607	180.	20000.	88121808
	1989	0.42622	140.	20000.	89012308
	1990	0.51703	300.	20000.	90022208
	1991	0.47685	60.	5000.	91070216
HIGH 3-Hour					
	1987	0.88989	210.	20000.	87110706
	1988	0.91675	260.	20000.	88091703
	1989	0.72984	270.	20000.	89092924
	1990	0.89915	190.	2000.	90041815
	1991	0.86240	180.	2000.	91081615
HIGH 1-Hour					
	1987	2.12755	160.	1500.	87080314
	1988	2.10877	230.	1500.	88081714
	1989	2.11156	40.	1500.	89061114
	1990	1.94449	50.	1500.	90062013
	1991	2.07621	60.	1500.	91041513
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.01274	250.	10000.	87123124
	1988	0.01474	240.	15000.	88123124
	1989	0.01233	300.	12000.	89123124
	1990	0.02189	240.	15000.	90123124
	1991	0.01613	230.	15000.	91123124
HIGH 24-Hour					
	1987	0.31847	250.	7000.	87081824
	1988	0.24728	180.	20000.	88121824
	1989	0.17788	310.	12000.	89091224
	1990	0.19492	230.	7000.	90051124
	1991	0.22539	60.	5000.	91070224
HIGH 8-Hour					
	1987	0.54250	250.	7000.	87081816
	1988	0.49059	180.	15000.	88121808
	1989	0.44109	140.	20000.	89012308
	1990	0.53345	300.	20000.	90022208
	1991	0.49073	250.	20000.	91113008
HIGH 3-Hour					
	1987	0.87189	190.	20000.	87100506
	1988	0.94615	260.	20000.	88091703
	1989	0.75433	270.	20000.	89092924
	1990	0.90368	190.	2000.	90041815
	1991	0.86520	180.	2000.	91081615
HIGH 1-Hour					
	1987	2.15158	240.	1500.	87052113
	1988	2.12020	230.	1500.	88081714
	1989	2.22275	260.	1500.	89061713
	1990	1.95603	50.	1500.	90062013
	1991	2.18688	210.	1500.	91072614
SOURCE GROUP ID:	LD5032				
Annual					
	1987	0.01439	250.	10000.	87123124
	1988	0.01647	240.	15000.	88123124
	1989	0.01490	300.	10000.	89123124
	1990	0.02502	240.	15000.	90123124
	1991	0.01856	250.	12000.	91123124
HIGH 24-Hour					
	1987	0.34183	250.	7000.	87081824
	1988	0.27478	180.	15000.	88121824
	1989	0.19990	310.	12000.	89091224
	1990	0.23159	240.	15000.	90121424
	1991	0.25345	170.	1500.	91081624
HIGH 8-Hour					
	1987	0.55794	250.	7000.	87081816
	1988	0.54743	180.	15000.	88121808

	1989	0.49406	140.	20000.	89012308
	1990	0.59150	300.	20000.	90022208
	1991	0.65172	170.	1500.	91081616
HIGH 3-Hour					
	1987	0.96729	190.	20000.	87100506
	1988	1.03121	260.	20000.	88091703
	1989	0.84170	270.	20000.	89092924
	1990	0.91891	190.	2000.	90041815
	1991	0.96263	250.	20000.	91111424
HIGH 1-Hour					
	1987	2.51901	20.	1500.	87092013
	1988	2.50010	230.	1500.	88080912
	1989	2.48085	50.	1500.	89072812
	1990	2.45957	50.	1500.	90090811
	1991	2.38766	330.	1500.	91072212
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.01498	250.	10000.	87123124
	1988	0.01712	240.	15000.	88123124
	1989	0.01571	300.	10000.	89123124
	1990	0.02604	240.	15000.	90123124
	1991	0.01952	250.	12000.	91123124
HIGH 24-Hour					
	1987	0.35170	250.	7000.	87081824
	1988	0.29003	180.	15000.	88121824
	1989	0.20981	310.	12000.	89091224
	1990	0.22563	240.	15000.	90121424
	1991	0.25746	170.	1500.	91081624
HIGH 8-Hour					
	1987	0.58485	250.	20000.	87081808
	1988	0.57237	180.	15000.	88121808
	1989	0.51748	140.	20000.	89012308
	1990	0.61687	300.	20000.	90022208
	1991	0.66204	170.	1500.	91081616
HIGH 3-Hour					
	1987	1.00897	190.	20000.	87100506
	1988	1.07783	260.	20000.	88091703
	1989	0.88016	270.	20000.	89092924
	1990	1.39410	50.	1500.	90090812
	1991	1.01158	250.	20000.	91111424
HIGH 1-Hour					
	1987	2.62173	20.	1500.	87092113
	1988	2.62899	20.	1500.	88082612
	1989	2.60576	90.	1500.	89051212
	1990	2.61700	80.	1500.	90082212
	1991	2.60613	270.	1500.	91062812

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB3 RELEASE 98056

ISCST3 OUTPUT FILE NUMBER 1 :GENNGC1.087
ISCST3 OUTPUT FILE NUMBER 2 :GENNGC1.088
ISCST3 OUTPUT FILE NUMBER 3 :GENNGC1.089
ISCST3 OUTPUT FILE NUMBER 4 :GENNGC1.090
ISCST3 OUTPUT FILE NUMBER 5 :GENNGC1.091
First title for last output file is: 1987 IPS DESOTO COUNTY SITE, AT EVERGLADES NP 1/22/00
Second title for last output file is: NATURAL GAS, GENERIC EMISSION RATES, 3 LOADS AND 2 TEMPERATURES

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BASE32				
Annual					
	1987	0.00143	473500.	2860000.	87123124
	1988	0.00122	530000.	2848600.	88123124
	1989	0.00127	459500.	2863200.	89123124
	1990	0.00110	480000.	2852500.	90123124
	1991	0.00121	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.04646	505000.	2832500.	87021224
	1988	0.03651	473500.	2860000.	88012324
	1989	0.04100	459500.	2863200.	89102824
	1990	0.03605	464000.	2860000.	90102524
	1991	0.04070	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.09916	505000.	2832500.	87021224
	1988	0.12762	520000.	2848600.	88121324
	1989	0.12300	459500.	2863200.	89102808
	1990	0.10065	464000.	2860000.	90102508
	1991	0.09428	454000.	2863200.	91112424
HIGH 3-Hour					
	1987	0.18533	488500.	2845500.	87091824
	1988	0.20691	530000.	2848600.	88110106
	1989	0.21953	459500.	2863200.	89102906
	1990	0.20072	469000.	2860000.	90120903
	1991	0.20098	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.37653	469000.	2860000.	87090321
	1988	0.38616	459500.	2863200.	88092601
	1989	0.38831	459500.	2863200.	89102707
	1990	0.43389	454000.	2863200.	90063023
	1991	0.40382	480000.	2852500.	91022806
SOURCE GROUP ID:	BASE95				
Annual					
	1987	0.00136	473500.	2860000.	87123124
	1988	0.00110	530000.	2848600.	88123124
	1989	0.00120	459500.	2863200.	89123124
	1990	0.00103	480000.	2852500.	90123124
	1991	0.00116	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.04157	505000.	2832500.	87021224
	1988	0.03543	473500.	2860000.	88012324
	1989	0.03849	459500.	2863200.	89102824
	1990	0.03483	464000.	2860000.	90102524
	1991	0.03848	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.09345	505000.	2832500.	87021224
	1988	0.12229	520000.	2848600.	88121324
	1989	0.11547	459500.	2863200.	89102808
	1990	0.09728	464000.	2860000.	90102508
	1991	0.09162	454000.	2863200.	91112424
HIGH 3-Hour					
	1987	0.17840	545000.	2844000.	87040703
	1988	0.19925	480000.	2852500.	88012303
	1989	0.20733	459500.	2863200.	89102906
	1990	0.19446	469000.	2860000.	90120903
	1991	0.19538	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.36181	469000.	2860000.	87090321
	1988	0.37080	459500.	2863200.	88092601
	1989	0.37303	459500.	2863200.	89102707
	1990	0.41461	454000.	2863200.	90063023
	1991	0.38703	480000.	2852500.	91022806
SOURCE GROUP ID:	LD7532				

Annual					
	1987	0.00154	473500.	2860000.	87123124
	1988	0.00132	530000.	2848600.	88123124
	1989	0.00137	459500.	2863200.	89123124
	1990	0.00119	480000.	2852500.	90123124
	1991	0.00134	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.05108	505000.	2832500.	87021224
	1988	0.03837	473500.	2860000.	88012324
	1989	0.04555	459500.	2863200.	89102824
	1990	0.03828	464000.	2860000.	90102524
	1991	0.04464	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.10955	505000.	2832500.	87021224
	1988	0.13711	520000.	2848600.	88121324
	1989	0.13663	459500.	2863200.	89102808
	1990	0.10684	464000.	2860000.	90102508
	1991	0.10678	514500.	2843000.	91021008
HIGH 3-Hour					
	1987	0.20971	488500.	2845500.	87091824
	1988	0.22023	530000.	2848600.	88110106
	1989	0.24148	459500.	2863200.	89102906
	1990	0.21145	469000.	2860000.	90120903
	1991	0.21046	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.40152	469000.	2860000.	87090321
	1988	0.41225	459500.	2863200.	88092601
	1989	0.41454	459500.	2863200.	89102707
	1990	0.46689	454000.	2863200.	90063023
	1991	0.43298	480000.	2852500.	91022806
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.00159	473500.	2860000.	87123124
	1988	0.00137	530000.	2848600.	88123124
	1989	0.00141	459500.	2863200.	89123124
	1990	0.00122	480000.	2852500.	90123124
	1991	0.00138	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.05272	505000.	2832500.	87021224
	1988	0.03925	473500.	2860000.	88012324
	1989	0.04717	459500.	2863200.	89102824
	1990	0.03908	464000.	2860000.	90102524
	1991	0.04603	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.11325	505000.	2832500.	87021224
	1988	0.14041	520000.	2848600.	88121324
	1989	0.14149	459500.	2863200.	89102808
	1990	0.10908	464000.	2860000.	90102508
	1991	0.11162	514500.	2843000.	91021008
HIGH 3-Hour					
	1987	0.21852	488500.	2845500.	87091824
	1988	0.22476	530000.	2848600.	88110106
	1989	0.24926	459500.	2863200.	89102906
	1990	0.21773	488500.	2845500.	90061203
	1991	0.21364	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.41006	469000.	2860000.	87090321
	1988	0.42117	459500.	2863200.	88092601
	1989	0.42349	459500.	2863200.	89102707
	1990	0.47826	454000.	2863200.	90063023
	1991	0.44296	480000.	2852500.	91022806
SOURCE GROUP ID:	LD5032				
Annual					
	1987	0.00173	473500.	2860000.	87123124
	1988	0.00145	530000.	2848600.	88123124
	1989	0.00154	459500.	2863200.	89123124
	1990	0.00135	480000.	2852500.	90123124
	1991	0.00150	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.05708	505000.	2832500.	87021224
	1988	0.04088	520000.	2848600.	88121324
	1989	0.05148	459500.	2863200.	89102824
	1990	0.04118	464000.	2860000.	90102524
	1991	0.04970	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.12305	505000.	2832500.	87021224
	1988	0.14895	520000.	2848600.	88121324

	1989	0.15443	459500.	2863200.	89102808
	1990	0.12074	488500.	2845500.	90061208
	1991	0.12459	514500.	2843000.	91021008
HIGH 3-Hour					
	1987	0.24238	488500.	2845500.	87091824
	1988	0.23635	530000.	2848600.	88110106
	1989	0.26975	459500.	2863200.	89102906
	1990	0.24149	488500.	2845500.	90061203
	1991	0.22161	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.45289	454000.	2863200.	87042206
	1988	0.44410	459500.	2863200.	88092601
	1989	0.45767	454000.	2863200.	89012403
	1990	0.50767	454000.	2863200.	90063023
	1991	0.46842	480000.	2852500.	91022806
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.00176	473500.	2860000.	87123124
	1988	0.00148	530000.	2848600.	88123124
	1989	0.00156	459500.	2863200.	89123124
	1990	0.00138	480000.	2852500.	90123124
	1991	0.00153	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.05870	505000.	2832500.	87021224
	1988	0.04183	520000.	2848600.	88121324
	1989	0.05275	459500.	2863200.	89102824
	1990	0.04178	464000.	2860000.	90102524
	1991	0.05076	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.12670	505000.	2832500.	87021224
	1988	0.15245	520000.	2848600.	88121324
	1989	0.15822	459500.	2863200.	89102808
	1990	0.12422	488500.	2845500.	90061208
	1991	0.12850	514500.	2843000.	91021008
HIGH 3-Hour					
	1987	0.24936	488500.	2845500.	87091824
	1988	0.23961	530000.	2848600.	88110106
	1989	0.27575	459500.	2863200.	89102906
	1990	0.24844	488500.	2845500.	90061203
	1991	0.22385	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.46708	454000.	2863200.	87042206
	1988	0.45053	459500.	2863200.	88092601
	1989	0.47205	454000.	2863200.	89012403
	1990	0.51595	454000.	2863200.	90063023
	1991	0.47569	480000.	2852500.	91022806

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

ISCBOB3 RELEASE 98056

ISCST3 OUTPUT FILE NUMBER 1 :GENFOC1.087
ISCST3 OUTPUT FILE NUMBER 2 :GENFOC1.088
ISCST3 OUTPUT FILE NUMBER 3 :GENFOC1.089
ISCST3 OUTPUT FILE NUMBER 4 :GENFOC1.090
ISCST3 OUTPUT FILE NUMBER 5 :GENFOC1.091
First title for last output file is: 1987 IPS DESOTO COUNTY SITE, AT EVERGLADES NP 1/22/00
Second title for last output file is: FUEL OIL, GENERIC EMISSION RATES, 3 LOADS AND 2 TEMPERATURES

AVERAGING TIME	YEAR	CONC (ug/m3)	DIR (deg) or X (m)	DIST (m) or Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BASE32				
Annual					
	1987	0.00141	473500.	2860000.	87123124
	1988	0.00119	530000.	2848600.	88123124
	1989	0.00125	459500.	2863200.	89123124
	1990	0.00109	480000.	2852500.	90123124
	1991	0.00119	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.04572	505000.	2832500.	87021224
	1988	0.03620	473500.	2860000.	88012324
	1989	0.04027	459500.	2863200.	89102824
	1990	0.03570	464000.	2860000.	90102524
	1991	0.04007	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.09750	505000.	2832500.	87021224
	1988	0.12607	520000.	2848600.	88121324
	1989	0.12082	459500.	2863200.	89102808
	1990	0.09968	464000.	2860000.	90102508
	1991	0.09352	454000.	2863200.	91112424
HIGH 3-Hour					
	1987	0.18247	545000.	2844000.	87040703
	1988	0.20471	530000.	2848600.	88110106
	1989	0.21600	459500.	2863200.	89102906
	1990	0.19891	469000.	2860000.	90120903
	1991	0.19938	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.37240	469000.	2860000.	87090321
	1988	0.38185	459500.	2863200.	88092601
	1989	0.38395	459500.	2863200.	89102707
	1990	0.42847	454000.	2863200.	90063023
	1991	0.39898	480000.	2852500.	91022806
SOURCE GROUP ID:	BASE95				
Annual					
	1987	0.00144	473500.	2860000.	87123124
	1988	0.00123	530000.	2848600.	88123124
	1989	0.00128	459500.	2863200.	89123124
	1990	0.00111	480000.	2852500.	90123124
	1991	0.00122	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.04721	505000.	2832500.	87021224
	1988	0.03683	473500.	2860000.	88012324
	1989	0.04174	459500.	2863200.	89102824
	1990	0.03640	464000.	2860000.	90102524
	1991	0.04134	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.10086	505000.	2832500.	87021224
	1988	0.12920	520000.	2848600.	88121324
	1989	0.12521	459500.	2863200.	89102808
	1990	0.10164	464000.	2860000.	90102508
	1991	0.09565	514500.	2843000.	91021008
HIGH 3-Hour					
	1987	0.18923	488500.	2845500.	87091824
	1988	0.20914	530000.	2848600.	88110106
	1989	0.22312	459500.	2863200.	89102906
	1990	0.20254	469000.	2860000.	90120903
	1991	0.20259	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.38068	469000.	2860000.	87090321
	1988	0.39049	459500.	2863200.	88092601
	1989	0.39269	459500.	2863200.	89102707
	1990	0.43934	454000.	2863200.	90063023
	1991	0.40870	480000.	2852500.	91022806
SOURCE GROUP ID:	LD7532				

Annual					
	1987	0.00154	473500.	2860000.	87123124
	1988	0.00131	530000.	2848600.	88123124
	1989	0.00137	459500.	2863200.	89123124
	1990	0.00119	480000.	2852500.	90123124
	1991	0.00134	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.05092	505000.	2832500.	87021224
	1988	0.03831	473500.	2860000.	88012324
	1989	0.04539	459500.	2863200.	89102824
	1990	0.03820	464000.	2860000.	90102524
	1991	0.04450	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.10919	505000.	2832500.	87021224
	1988	0.13678	520000.	2848600.	88121324
	1989	0.13615	459500.	2863200.	89102808
	1990	0.10663	464000.	2860000.	90102508
	1991	0.10632	514500.	2843000.	91021008
HIGH 3-Hour					
	1987	0.20884	488500.	2845500.	87091824
	1988	0.21978	530000.	2848600.	88110106
	1989	0.24072	459500.	2863200.	89102906
	1990	0.21110	469000.	2860000.	90120903
	1991	0.21014	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.40067	469000.	2860000.	87090321
	1988	0.41136	459500.	2863200.	88092601
	1989	0.41365	459500.	2863200.	89102707
	1990	0.46576	454000.	2863200.	90063023
	1991	0.43199	480000.	2852500.	91022806
SOURCE GROUP ID:	LD7595				
Annual					
	1987	0.00156	473500.	2860000.	87123124
	1988	0.00134	530000.	2848600.	88123124
	1989	0.00140	459500.	2863200.	89123124
	1990	0.00121	480000.	2852500.	90123124
	1991	0.00137	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.05209	505000.	2832500.	87021224
	1988	0.03901	473500.	2860000.	88012324
	1989	0.04655	459500.	2863200.	89102824
	1990	0.03877	464000.	2860000.	90102524
	1991	0.04550	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.11183	505000.	2832500.	87021224
	1988	0.13915	520000.	2848600.	88121324
	1989	0.13963	459500.	2863200.	89102808
	1990	0.10822	464000.	2860000.	90102508
	1991	0.10976	514500.	2843000.	91021008
HIGH 3-Hour					
	1987	0.21513	488500.	2845500.	87091824
	1988	0.22303	530000.	2848600.	88110106
	1989	0.24628	459500.	2863200.	89102906
	1990	0.21435	488500.	2845500.	90061203
	1991	0.21243	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.40681	469000.	2860000.	87090321
	1988	0.41777	459500.	2863200.	88092601
	1989	0.42008	459500.	2863200.	89102707
	1990	0.47392	454000.	2863200.	90063023
	1991	0.43916	480000.	2852500.	91022806
SOURCE GROUP ID:	LD5032				
Annual					
	1987	0.00171	473500.	2860000.	87123124
	1988	0.00143	530000.	2848600.	88123124
	1989	0.00151	459500.	2863200.	89123124
	1990	0.00133	480000.	2852500.	90123124
	1991	0.00149	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.05618	505000.	2832500.	87021224
	1988	0.04051	473500.	2860000.	88012324
	1989	0.05058	459500.	2863200.	89102824
	1990	0.04074	464000.	2860000.	90102524
	1991	0.04894	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.12103	505000.	2832500.	87021224
	1988	0.14721	520000.	2848600.	88121324

	1989	0.15174	459500.	2863200.	89102808
	1990	0.11823	488500.	2845500.	90061208
	1991	0.12189	514500.	2843000.	91021008
HIGH 3-Hour					
	1987	0.23733	488500.	2845500.	87091824
	1988	0.23399	530000.	2848600.	88110106
	1989	0.26552	459500.	2863200.	89102906
	1990	0.23647	488500.	2845500.	90061203
	1991	0.22001	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.44288	454000.	2863200.	87042206
	1988	0.43940	459500.	2863200.	88092601
	1989	0.44770	454000.	2863200.	89012403
	1990	0.50161	454000.	2863200.	90063023
	1991	0.46327	480000.	2852500.	91022806
SOURCE GROUP ID:	LD5095				
Annual					
	1987	0.00175	473500.	2860000.	87123124
	1988	0.00147	530000.	2848600.	88123124
	1989	0.00155	459500.	2863200.	89123124
	1990	0.00137	480000.	2852500.	90123124
	1991	0.00152	454000.	2863200.	91123124
HIGH 24-Hour					
	1987	0.05794	505000.	2832500.	87021224
	1988	0.04133	520000.	2848600.	88121324
	1989	0.05232	459500.	2863200.	89102824
	1990	0.04158	464000.	2860000.	90102524
	1991	0.05041	454000.	2863200.	91101124
HIGH 8-Hour					
	1987	0.12498	505000.	2832500.	87021224
	1988	0.15061	520000.	2848600.	88121324
	1989	0.15695	459500.	2863200.	89102808
	1990	0.12304	488500.	2845500.	90061208
	1991	0.12719	514500.	2843000.	91021008
HIGH 3-Hour					
	1987	0.24699	488500.	2845500.	87091824
	1988	0.23852	530000.	2848600.	88110106
	1989	0.27375	459500.	2863200.	89102906
	1990	0.24609	488500.	2845500.	90061203
	1991	0.22311	454000.	2863200.	91112421
HIGH 1-Hour					
	1987	0.46231	454000.	2863200.	87042206
	1988	0.44837	459500.	2863200.	88092601
	1989	0.46725	454000.	2863200.	89012403
	1990	0.51316	454000.	2863200.	90063023
	1991	0.47328	480000.	2852500.	91022806

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

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CO STARTING
CO TITLEONE 1987 IPS DESOTO COUNTY SITE                                    1/22/00
CO TITLETWO NATURAL GAS, GENERIC EMISSION RATES, 3 LOADS AND 2 TEMPERATURES
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME  PERIOD 24 8 3 1
CO POLLUTID GEN
CO DCAYCOEF     .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
**          SRCID SRCTYP        XS            YS            ZS
** MODELING ORIGIN CT 2 STACK LOCATION
** LOCATION IS USED FOR POLAR DISCRETE RECEPTORS.
**  CT STACK NUMBER CODE
** -----------------------
**  A -  CT 1
**  B -  CT 2
**  C -  CT 3
** Source Location Cards:
**          SRCID SRCTYP      XS        YS        ZS
**   UTM                      (m)       (m)       (m)
SO LOCATION  BASE32A  POINT  -35.36    0.0       0.0
SO LOCATION  BASE32B  POINT    0.00    0.0       0.0
SO LOCATION  BASE32C  POINT   35.36    0.0       0.0
SO LOCATION  BASE95A  POINT  -35.36    0.0       0.0
SO LOCATION  BASE95B  POINT    0.00    0.0       0.0
SO LOCATION  BASE95C  POINT   35.36    0.0       0.0
SO LOCATION  LD7532A  POINT  -35.36    0.0       0.0
SO LOCATION  LD7532B  POINT    0.00    0.0       0.0
SO LOCATION  LD7532C  POINT   35.36    0.0       0.0
SO LOCATION  LD7595A  POINT  -35.36    0.0       0.0
SO LOCATION  LD7595B  POINT    0.00    0.0       0.0
SO LOCATION  LD7595C  POINT   35.36    0.0       0.0
SO LOCATION  LD5032A  POINT  -35.36    0.0       0.0
SO LOCATION  LD5032B  POINT    0.00    0.0       0.0
SO LOCATION  LD5032C  POINT   35.36    0.0       0.0
SO LOCATION  LD5095A  POINT  -35.36    0.0       0.0
SO LOCATION  LD5095B  POINT    0.00    0.0       0.0
SO LOCATION  LD5095C  POINT   35.36    0.0       0.0
** Source Parameter Cards:
** POINT:   SRCID              QS       HS        TS        VS        DS
**                           (g/s)     (m)       (K)      (m/s)      (m)
SO SRCPARAM   BASE32A      3.333     18.3      864.8     36.18      6.71
SO SRCPARAM   BASE32B      3.333     18.3      864.8     36.18      6.71
SO SRCPARAM   BASE32C      3.333     18.3      864.8     36.18      6.71
SO SRCPARAM   BASE95A      3.333     18.3      885.9     38.86      6.71
SO SRCPARAM   BASE95B      3.333     18.3      885.9     38.86      6.71
SO SRCPARAM   BASE95C      3.333     18.3      885.9     38.86      6.71
SO SRCPARAM   LD7532A      3.333     18.3      905.4     30.63      6.71
SO SRCPARAM   LD7532B      3.333     18.3      905.4     30.63      6.71
SO SRCPARAM   LD7532C      3.333     18.3      905.4     30.63      6.71
SO SRCPARAM   LD7595A      3.333     18.3      918.2     28.96      6.71
SO SRCPARAM   LD7595B      3.333     18.3      918.2     28.96      6.71
SO SRCPARAM   LD7595C      3.333     18.3      918.2     28.96      6.71
SO SRCPARAM   LD5032A      3.333     18.3      905.9     25.66      6.71
SO SRCPARAM   LD5032B      3.333     18.3      905.9     25.66      6.71
SO SRCPARAM   LD5032C      3.333     18.3      905.9     25.66      6.71
SO SRCPARAM   LD5095A      3.333     18.3      922.0     24.54      6.71
SO SRCPARAM   LD5095B      3.333     18.3      922.0     24.54      6.71
SO SRCPARAM   LD5095C      3.333     18.3      922.0     24.54      6.71

SO BUILDHGT BASE32A-BASE95A      6.71     6.71     6.71    14.33     0.00     0.00
SO BUILDHGT BASE32A-BASE95A      0.00     0.00     0.00     0.00     0.00     0.00
SO BUILDHGT BASE32A-BASE95A      0.00     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE32A-BASE95A     14.33    14.33    14.33    14.33    14.33    14.33
SO BUILDHGT BASE32A-BASE95A      6.71     6.71     0.00     0.00     0.00     0.00
SO BUILDHGT BASE32A-BASE95A      0.00     6.71     6.71     6.71     6.71     6.71
SO BUILDWID BASE32A-BASE95A     11.23    12.97    14.32    15.46     0.00     0.00
SO BUILDWID BASE32A-BASE95A      0.00     0.00     0.00     0.00     0.00     0.00
SO BUILDWID BASE32A-BASE95A      0.00    15.23    14.32    12.97    11.23     9.14
SO BUILDWID BASE32A-BASE95A     12.71    14.06    14.99    15.46    15.46    14.99
SO BUILDWID BASE32A-BASE95A     15.16    14.19     0.00     0.00     0.00     0.00
SO BUILDWID BASE32A-BASE95A      0.00    15.23    14.32    12.97    11.23     9.14
SO BUILDHGT LD5032A-LD7595A      6.71     6.71     6.71    14.33     0.00     0.00
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SO BUILDHGT LD5032A-LD7595A     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT LD5032A-LD7595A     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT LD5032A-LD7595A    14.33   14.33   14.33   14.33   14.33   14.33
SO BUILDHGT LD5032A-LD7595A     6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDHGT LD5032A-LD7595A     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID LD5032A-LD7595A    11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID LD5032A-LD7595A     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5032A-LD7595A     0.00   15.23   14.32   12.97   11.23    9.14
SO BUILDWID LD5032A-LD7595A    12.71   14.06   14.99   15.46   15.46   14.99
SO BUILDWID LD5032A-LD7595A    15.16   14.19    0.00    0.00    0.00    0.00
SO BUILDWID LD5032A-LD7595A     0.00   15.23   14.32   12.97   11.23    9.14


SO BUILDHGT BASE32B-BASE95B     6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT BASE32B-BASE95B     0.00    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT BASE32B-BASE95B    14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT BASE32B-BASE95B    14.33   14.33   14.33   14.33   14.33   14.33
SO BUILDHGT BASE32B-BASE95B     6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDHGT BASE32B-BASE95B     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID BASE32B-BASE95B    11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID BASE32B-BASE95B     0.00    0.00    0.00   14.19   15.16   15.66
SO BUILDWID BASE32B-BASE95B    15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID BASE32B-BASE95B    12.71   14.06   14.99   15.46   15.46   14.99
SO BUILDWID BASE32B-BASE95B    15.16   14.19    0.00    0.00    0.00    0.00
SO BUILDWID BASE32B-BASE95B     0.00   15.23   14.32   12.97   11.23    9.14
SO BUILDHGT LD5032B-LD7595B     6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT LD5032B-LD7595B     0.00    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT LD5032B-LD7595B    14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT LD5032B-LD7595B    14.33   14.33   14.33   14.33   14.33   14.33
SO BUILDHGT LD5032B-LD7595B     6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDHGT LD5032B-LD7595B     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID LD5032B-LD7595B    11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID LD5032B-LD7595B     0.00    0.00    0.00   14.19   15.16   15.66
SO BUILDWID LD5032B-LD7595B    15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID LD5032B-LD7595B    12.71   14.06   14.99   15.46   15.46   14.99
SO BUILDWID LD5032B-LD7595B    15.16   14.19    0.00    0.00    0.00    0.00
SO BUILDWID LD5032B-LD7595B     0.00   15.23   14.32   12.97   11.23    9.14


SO BUILDHGT BASE32C-BASE95C     6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT BASE32C-BASE95C     0.00    0.00    0.00    6.71    6.71   14.33
SO BUILDHGT BASE32C-BASE95C    14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT BASE32C-BASE95C    14.33   14.33   14.33   14.33   15.24   15.24
SO BUILDHGT BASE32C-BASE95C    15.24   15.24   15.24    0.00    0.00    0.00
SO BUILDHGT BASE32C-BASE95C     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID BASE32C-BASE95C    11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID BASE32C-BASE95C     0.00    0.00    0.00   14.19   15.16   14.99
SO BUILDWID BASE32C-BASE95C    15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID BASE32C-BASE95C    12.71   14.06   14.99   15.46   58.42   61.15
SO BUILDWID BASE32C-BASE95C    28.64   30.02   30.48    0.00    0.00    0.00
SO BUILDWID BASE32C-BASE95C     0.00   15.23   14.32   12.97   11.23    9.14
SO BUILDHGT LD5032C-LD7595C     6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT LD5032C-LD7595C     0.00    0.00    0.00    6.71    6.71   14.33
SO BUILDHGT LD5032C-LD7595C    14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT LD5032C-LD7595C    14.33   14.33   14.33   14.33   15.24   15.24
SO BUILDHGT LD5032C-LD7595C    15.24   15.24   15.24    0.00    0.00    0.00
SO BUILDHGT LD5032C-LD7595C     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID LD5032C-LD7595C    11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID LD5032C-LD7595C     0.00    0.00    0.00   14.19   15.16   14.99
SO BUILDWID LD5032C-LD7595C    15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID LD5032C-LD7595C    12.71   14.06   14.99   15.46   58.42   61.15
SO BUILDWID LD5032C-LD7595C    28.64   30.02   30.48    0.00    0.00    0.00
SO BUILDWID LD5032C-LD7595C     0.00   15.23   14.32   12.97   11.23    9.14

SO EMISUNIT    .100000E+07 (GRAMS/SEC)         (MICROGRAMS/CUBIC-METER)
SO SRCGROUP BASE32 BASE32A BASE32B BASE32C
SO SRCGROUP BASE95 BASE95A BASE95B BASE95C
SO SRCGROUP LD7532 LD7532A LD7532B LD7532C
SO SRCGROUP LD7595 LD7595A LD7595B LD7595C
SO SRCGROUP LD5032 LD5032A LD5032B LD5032C
SO SRCGROUP LD5095 LD5095A LD5095B LD5095C
SO FINISHED

RE STARTING
RE GRIDPOLR POL STA
RE GRIDPOLR POL ORIG  0.0    0.0
RE GRIDPOLR POL DIST  100 200 300  500 700 1000 1500 2000 2500 3000 4000 5000
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RE GRIDPOLR POL DIST  7000 10000 12000 15000 20000 25000 30000
RE GRIDPOLR POL GDIR  36  10.00  10.00
RE GRIDPOLR POL END
RE FINISHED

ME STARTING
ME INPUTFIL P:\MET\FMYTPA87.ASC
ME ANEMHGHT  20 FEET
ME SURFDATA  12835  1987            FTMYERS
ME UAIRDATA  12842  1987            RUSKIN
ME WINDCATS    1.54    3.09    5.14    8.23   10.80
ME FINISHED


OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
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CO STARTING
CO TITLEONE 1987 IPS DESOTO COUNTY SITE                        1/22/00
CO TITLETWO FUEL OIL, GENERIC EMISSION RATES, 3 LOADS AND 2 TEMPERATURES
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME  PERIOD 24 8 3 1
CO POLLUTID GEN
CO DCAYCOEF     .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
**          SRCID SRCTYP        XS             YS             ZS
** MODELING ORIGIN CT 2 STACK LOCATION
** LOCATION IS USED FOR POLAR DISCRETE RECEPTORS.
**  CT STACK NUMBER CODE
** -------------------------
**  A -  CT 1
**  B -  CT 2
**  C -  CT 3
** Source Location Cards:
**          SRCID SRCTYP      XS        YS        ZS
**   UTM                     (m)       (m)       (m)
SO LOCATION  BASE32A  POINT  -35.36    0.0       0.0
SO LOCATION  BASE32B  POINT    0.00    0.0       0.0
SO LOCATION  BASE32C  POINT   35.36    0.0       0.0
SO LOCATION  BASE95A  POINT  -35.36    0.0       0.0
SO LOCATION  BASE95B  POINT    0.00    0.0       0.0
SO LOCATION  BASE95C  POINT   35.36    0.0       0.0
SO LOCATION  LD7532A  POINT  -35.36    0.0       0.0
SO LOCATION  LD7532B  POINT    0.00    0.0       0.0
SO LOCATION  LD7532C  POINT   35.36    0.0       0.0
SO LOCATION  LD7595A  POINT  -35.36    0.0       0.0
SO LOCATION  LD7595B  POINT    0.00    0.0       0.0
SO LOCATION  LD7595C  POINT   35.36    0.0       0.0
SO LOCATION  LD5032A  POINT  -35.36    0.0       0.0
SO LOCATION  LD5032B  POINT    0.00    0.0       0.0
SO LOCATION  LD5032C  POINT   35.36    0.0       0.0
SO LOCATION  LD5095A  POINT  -35.36    0.0       0.0
SO LOCATION  LD5095B  POINT    0.00    0.0       0.0
SO LOCATION  LD5095C  POINT   35.36    0.0       0.0
** Source Parameter Cards:
** POINT:   SRCID              QS       HS         TS        VS        DS
**                            (g/s)     (m)        (K)      (m/s)      (m)
SO SRCPARAM    BASE32A       3.333     18.3       853.2     37.31     6.71
SO SRCPARAM    BASE32B       3.333     18.3       853.2     37.31     6.71
SO SRCPARAM    BASE32C       3.333     18.3       853.2     37.31     6.71
SO SRCPARAM    BASE95A       3.333     18.3       878.2     35.05     6.71
SO SRCPARAM    BASE95B       3.333     18.3       878.2     35.05     6.71
SO SRCPARAM    BASE95C       3.333     18.3       878.2     35.05     6.71
SO SRCPARAM    LD7532A       3.333     18.3       905.4     30.78     6.71
SO SRCPARAM    LD7532B       3.333     18.3       905.4     30.78     6.71
SO SRCPARAM    LD7532C       3.333     18.3       905.4     30.78     6.71
SO SRCPARAM    LD7595A       3.333     18.3       914.3     29.57     6.71
SO SRCPARAM    LD7595B       3.333     18.3       914.3     29.57     6.71
SO SRCPARAM    LD7595C       3.333     18.3       914.3     29.57     6.71
SO SRCPARAM    LD5032A       3.333     18.3       922.0     26.12     6.71
SO SRCPARAM    LD5032B       3.333     18.3       922.0     26.12     6.71
SO SRCPARAM    LD5032C       3.333     18.3       922.0     26.12     6.71
SO SRCPARAM    LD5095A       3.333     18.3       922.0     24.84     6.71
SO SRCPARAM    LD5095B       3.333     18.3       922.0     24.84     6.71
SO SRCPARAM    LD5095C       3.333     18.3       922.0     24.84     6.71

SO BUILDHGT BASE32A-BASE95A      6.71     6.71     6.71    14.33     0.00     0.00
SO BUILDHGT BASE32A-BASE95A      0.00     0.00     0.00     0.00     0.00     0.00
SO BUILDHGT BASE32A-BASE95A      0.00     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE32A-BASE95A     14.33    14.33    14.33    14.33    14.33    14.33
SO BUILDHGT BASE32A-BASE95A      6.71     6.71     0.00     0.00     0.00     0.00
SO BUILDHGT BASE32A-BASE95A      0.00     6.71     6.71     6.71     6.71     6.71
SO BUILDWID BASE32A-BASE95A     11.23    12.97    14.32    15.46     0.00     0.00
SO BUILDWID BASE32A-BASE95A      0.00     0.00     0.00     0.00     0.00     0.00
SO BUILDWID BASE32A-BASE95A      0.00    15.23    14.32    12.97    11.23     9.14
SO BUILDWID BASE32A-BASE95A     12.71    14.06    14.99    15.46    15.46    14.99
SO BUILDWID BASE32A-BASE95A     15.16    14.19     0.00     0.00     0.00     0.00
SO BUILDWID BASE32A-BASE95A      0.00    15.23    14.32    12.97    11.23     9.14
SO BUILDHGT LD5032A-LD7595A      6.71     6.71     6.71    14.33     0.00     0.00
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SO BUILDHGT LD5032A-LD7595A    0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT LD5032A-LD7595A    0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT LD5032A-LD7595A   14.33   14.33   14.33   14.33   14.33   14.33
SO BUILDHGT LD5032A-LD7595A    6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDHGT LD5032A-LD7595A    0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID LD5032A-LD7595A   11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID LD5032A-LD7595A    0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5032A-LD7595A    0.00   15.23   14.32   12.97   11.23    9.14
SO BUILDWID LD5032A-LD7595A   12.71   14.06   14.99   15.46   15.46   14.99
SO BUILDWID LD5032A-LD7595A   15.16   14.19    0.00    0.00    0.00    0.00
SO BUILDWID LD5032A-LD7595A    0.00   15.23   14.32   12.97   11.23    9.14


SO BUILDHGT BASE32B-BASE95B    6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT BASE32B-BASE95B    0.00    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT BASE32B-BASE95B   14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT BASE32B-BASE95B   14.33   14.33   14.33   14.33   14.33   14.33
SO BUILDHGT BASE32B-BASE95B    6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDHGT BASE32B-BASE95B    0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID BASE32B-BASE95B   11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID BASE32B-BASE95B    0.00    0.00    0.00   14.19   15.16   15.66
SO BUILDWID BASE32B-BASE95B   15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID BASE32B-BASE95B   12.71   14.06   14.99   15.46   15.46   14.99
SO BUILDWID BASE32B-BASE95B   15.16   14.19    0.00    0.00    0.00    0.00
SO BUILDWID BASE32B-BASE95B    0.00   15.23   14.32   12.97   11.23    9.14
SO BUILDHGT LD5032B-LD7595B    6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT LD5032B-LD7595B    0.00    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT LD5032B-LD7595B   14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT LD5032B-LD7595B   14.33   14.33   14.33   14.33   14.33   14.33
SO BUILDHGT LD5032B-LD7595B    6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDHGT LD5032B-LD7595B    0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID LD5032B-LD7595B   11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID LD5032B-LD7595B    0.00    0.00    0.00   14.19   15.16   15.66
SO BUILDWID LD5032B-LD7595B   15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID LD5032B-LD7595B   12.71   14.06   14.99   15.46   15.46   14.99
SO BUILDWID LD5032B-LD7595B   15.16   14.19    0.00    0.00    0.00    0.00
SO BUILDWID LD5032B-LD7595B    0.00   15.23   14.32   12.97   11.23    9.14


SO BUILDHGT BASE32C-BASE95C    6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT BASE32C-BASE95C    0.00    0.00    0.00    6.71    6.71   14.33
SO BUILDHGT BASE32C-BASE95C   14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT BASE32C-BASE95C   14.33   14.33   14.33   14.33   15.24   15.24
SO BUILDHGT BASE32C-BASE95C   15.24   15.24   15.24    0.00    0.00    0.00
SO BUILDHGT BASE32C-BASE95C    0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID BASE32C-BASE95C   11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID BASE32C-BASE95C    0.00    0.00    0.00   14.19   15.16   14.99
SO BUILDWID BASE32C-BASE95C   15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID BASE32C-BASE95C   12.71   14.06   14.99   15.46   58.42   61.15
SO BUILDWID BASE32C-BASE95C   28.64   30.02   30.48    0.00    0.00    0.00
SO BUILDWID BASE32C-BASE95C    0.00   15.23   14.32   12.97   11.23    9.14
SO BUILDHGT LD5032C-LD7595C    6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT LD5032C-LD7595C    0.00    0.00    0.00    6.71    6.71   14.33
SO BUILDHGT LD5032C-LD7595C   14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT LD5032C-LD7595C   14.33   14.33   14.33   14.33   15.24   15.24
SO BUILDHGT LD5032C-LD7595C   15.24   15.24   15.24    0.00    0.00    0.00
SO BUILDHGT LD5032C-LD7595C    0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID LD5032C-LD7595C   11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID LD5032C-LD7595C    0.00    0.00    0.00   14.19   15.16   14.99
SO BUILDWID LD5032C-LD7595C   15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID LD5032C-LD7595C   12.71   14.06   14.99   15.46   58.42   61.15
SO BUILDWID LD5032C-LD7595C   28.64   30.02   30.48    0.00    0.00    0.00
SO BUILDWID LD5032C-LD7595C    0.00   15.23   14.32   12.97   11.23    9.14

SO EMISUNIT    .100000E+07 (GRAMS/SEC)         (MICROGRAMS/CUBIC-METER)
SO SRCGROUP BASE32 BASE32A BASE32B BASE32C
SO SRCGROUP BASE95 BASE95A BASE95B BASE95C
SO SRCGROUP LD7532 LD7532A LD7532B LD7532C
SO SRCGROUP LD7595 LD7595A LD7595B LD7595C
SO SRCGROUP LD5032 LD5032A LD5032B LD5032C
SO SRCGROUP LD5095 LD5095A LD5095B LD5095C
SO FINISHED

RE STARTING
RE GRIDPOLR POL STA
RE GRIDPOLR POL ORIG  0.0    0.0
RE GRIDPOLR POL DIST  100 200 300  500 700 1000 1500 2000 2500 3000 4000 5000
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RE GRIDPOLR POL DIST  7000 10000 12000 15000 20000 25000 30000
RE GRIDPOLR POL GDIR  36  10.00  10.00
RE GRIDPOLR POL END
RE FINISHED

ME STARTING
ME INPUTFIL P:\MET\FMYTPA87.ASC
ME ANEMHGHT  20 FEET
ME SURFDATA  12835  1987            FTMYERS
ME UAIRDATA  12842  1987            RUSKIN
ME WINDCATS    1.54     3.09     5.14     8.23    10.80
ME FINISHED


OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
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CO STARTING
CO TITLEONE 1987 IPS DESOTO COUNTY SITE, AT EVERGLADES NP          1/22/00
CO TITLETWO NATURAL GAS, GENERIC EMISSION RATES, 3 LOADS AND 2 TEMPERATURES
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME  PERIOD 24 8 3 1
CO POLLUTID GEN
CO DCAYCOEF     .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
**         SRCID SRCTYP        XS            YS             ZS
** MODELING ORIGIN CT 2 STACK LOCATION
** LOCATION IS USED FOR POLAR DISCRETE RECEPTORS.
**  CT STACK NUMBER CODE
** -----------------------
**  A -  CT 1
**  B -  CT 2
**  C -  CT 3
** Source Location Cards:
**         SRCID SRCTYP      XS        YS        ZS
**   UTM                     (m)       (m)       (m)
SO LOCATION  BASE32A  POINT  419700  3011500    0.0
SO LOCATION  BASE32B  POINT  419700  3011500    0.0
SO LOCATION  BASE32C  POINT  419700  3011500    0.0
SO LOCATION  BASE95A  POINT  419700  3011500    0.0
SO LOCATION  BASE95B  POINT  419700  3011500    0.0
SO LOCATION  BASE95C  POINT  419700  3011500    0.0
SO LOCATION  LD7532A  POINT  419700  3011500    0.0
SO LOCATION  LD7532B  POINT  419700  3011500    0.0
SO LOCATION  LD7532C  POINT  419700  3011500    0.0
SO LOCATION  LD7595A  POINT  419700  3011500    0.0
SO LOCATION  LD7595B  POINT  419700  3011500    0.0
SO LOCATION  LD7595C  POINT  419700  3011500    0.0
SO LOCATION  LD5032A  POINT  419700  3011500    0.0
SO LOCATION  LD5032B  POINT  419700  3011500    0.0
SO LOCATION  LD5032C  POINT  419700  3011500    0.0
SO LOCATION  LD5095A  POINT  419700  3011500    0.0
SO LOCATION  LD5095B  POINT  419700  3011500    0.0
SO LOCATION  LD5095C  POINT  419700  3011500    0.0
** Source Parameter Cards:
** POINT:   SRCID            QS       HS        TS        VS        DS
**                          (g/s)     (m)       (K)      (m/s)      (m)
SO SRCPARAM   BASE32A     3.333     18.3      864.8     36.18     6.71
SO SRCPARAM   BASE32B     3.333     18.3      864.8     36.18     6.71
SO SRCPARAM   BASE32C     3.333     18.3      864.8     36.18     6.71
SO SRCPARAM   BASE95A     3.333     18.3      885.9     38.86     6.71
SO SRCPARAM   BASE95B     3.333     18.3      885.9     38.86     6.71
SO SRCPARAM   BASE95C     3.333     18.3      885.9     38.86     6.71
SO SRCPARAM   LD7532A     3.333     18.3      905.4     30.63     6.71
SO SRCPARAM   LD7532B     3.333     18.3      905.4     30.63     6.71
SO SRCPARAM   LD7532C     3.333     18.3      905.4     30.63     6.71
SO SRCPARAM   LD7595A     3.333     18.3      918.2     28.96     6.71
SO SRCPARAM   LD7595B     3.333     18.3      918.2     28.96     6.71
SO SRCPARAM   LD7595C     3.333     18.3      918.2     28.96     6.71
SO SRCPARAM   LD5032A     3.333     18.3      905.9     25.66     6.71
SO SRCPARAM   LD5032B     3.333     18.3      905.9     25.66     6.71
SO SRCPARAM   LD5032C     3.333     18.3      905.9     25.66     6.71
SO SRCPARAM   LD5095A     3.333     18.3      922.0     24.54     6.71
SO SRCPARAM   LD5095B     3.333     18.3      922.0     24.54     6.71
SO SRCPARAM   LD5095C     3.333     18.3      922.0     24.54     6.71

SO BUILDHGT BASE32A-BASE95A      6.71     6.71     6.71    14.33     0.00     0.00
SO BUILDHGT BASE32A-BASE95A      0.00     0.00     0.00     0.00     0.00     0.00
SO BUILDHGT BASE32A-BASE95A      0.00     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE32A-BASE95A     14.33    14.33    14.33    14.33    14.33    14.33
SO BUILDHGT BASE32A-BASE95A      6.71     6.71     0.00     0.00     0.00     0.00
SO BUILDHGT BASE32A-BASE95A      0.00     6.71     6.71     6.71     6.71     6.71
SO BUILDWID BASE32A-BASE95A     11.23    12.97    14.32    15.46     0.00     0.00
SO BUILDWID BASE32A-BASE95A      0.00     0.00     0.00     0.00     0.00     0.00
SO BUILDWID BASE32A-BASE95A      0.00    15.23    14.32    12.97    11.23     9.14
SO BUILDWID BASE32A-BASE95A     12.71    14.06    14.99    15.46    15.46    14.99
SO BUILDWID BASE32A-BASE95A     15.16    14.19     0.00     0.00     0.00     0.00
SO BUILDWID BASE32A-BASE95A      0.00    15.23    14.32    12.97    11.23     9.14
SO BUILDHGT LD5032A-LD7595A      6.71     6.71     6.71    14.33     0.00     0.00
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SO BUILDHGT LD5032A-LD7595A     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDHGT LD5032A-LD7595A     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT LD5032A-LD7595A    14.33   14.33   14.33   14.33   14.33   14.33
SO BUILDHGT LD5032A-LD7595A     6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDHGT LD5032A-LD7595A     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID LD5032A-LD7595A    11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID LD5032A-LD7595A     0.00    0.00    0.00    0.00    0.00    0.00
SO BUILDWID LD5032A-LD7595A     0.00   15.23   14.32   12.97   11.23    9.14
SO BUILDWID LD5032A-LD7595A    12.71   14.06   14.99   15.46   15.46   14.99
SO BUILDWID LD5032A-LD7595A    15.16   14.19    0.00    0.00    0.00    0.00
SO BUILDWID LD5032A-LD7595A     0.00   15.23   14.32   12.97   11.23    9.14


SO BUILDHGT BASE32B-BASE95B     6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT BASE32B-BASE95B     0.00    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT BASE32B-BASE95B    14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT BASE32B-BASE95B    14.33   14.33   14.33   14.33   14.33   14.33
SO BUILDHGT BASE32B-BASE95B     6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDHGT BASE32B-BASE95B     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID BASE32B-BASE95B    11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID BASE32B-BASE95B     0.00    0.00    0.00   14.19   15.16   15.66
SO BUILDWID BASE32B-BASE95B    15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID BASE32B-BASE95B    12.71   14.06   14.99   15.46   15.46   14.99
SO BUILDWID BASE32B-BASE95B    15.16   14.19    0.00    0.00    0.00    0.00
SO BUILDWID BASE32B-BASE95B     0.00   15.23   14.32   12.97   11.23    9.14
SO BUILDHGT LD5032B-LD7595B     6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT LD5032B-LD7595B     0.00    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT LD5032B-LD7595B    14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT LD5032B-LD7595B    14.33   14.33   14.33   14.33   14.33   14.33
SO BUILDHGT LD5032B-LD7595B     6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDHGT LD5032B-LD7595B     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID LD5032B-LD7595B    11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID LD5032B-LD7595B     0.00    0.00    0.00   14.19   15.16   15.66
SO BUILDWID LD5032B-LD7595B    15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID LD5032B-LD7595B    12.71   14.06   14.99   15.46   15.46   14.99
SO BUILDWID LD5032B-LD7595B    15.16   14.19    0.00    0.00    0.00    0.00
SO BUILDWID LD5032B-LD7595B     0.00   15.23   14.32   12.97   11.23    9.14


SO BUILDHGT BASE32C-BASE95C     6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT BASE32C-BASE95C     0.00    0.00    0.00    6.71    6.71   14.33
SO BUILDHGT BASE32C-BASE95C    14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT BASE32C-BASE95C    14.33   14.33   14.33   14.33   15.24   15.24
SO BUILDHGT BASE32C-BASE95C    15.24   15.24   15.24    0.00    0.00    0.00
SO BUILDHGT BASE32C-BASE95C     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID BASE32C-BASE95C    11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID BASE32C-BASE95C     0.00    0.00    0.00   14.19   15.16   14.99
SO BUILDWID BASE32C-BASE95C    15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID BASE32C-BASE95C    12.71   14.06   14.99   15.46   58.42   61.15
SO BUILDWID BASE32C-BASE95C    28.64   30.02   30.48    0.00    0.00    0.00
SO BUILDWID BASE32C-BASE95C     0.00   15.23   14.32   12.97   11.23    9.14
SO BUILDHGT LD5032C-LD7595C     6.71    6.71    6.71   14.33    0.00    0.00
SO BUILDHGT LD5032C-LD7595C     0.00    0.00    0.00    6.71    6.71   14.33
SO BUILDHGT LD5032C-LD7595C    14.33   14.33   14.33   14.33    6.71    6.71
SO BUILDHGT LD5032C-LD7595C    14.33   14.33   14.33   14.33   15.24   15.24
SO BUILDHGT LD5032C-LD7595C    15.24   15.24   15.24    0.00    0.00    0.00
SO BUILDHGT LD5032C-LD7595C     0.00    6.71    6.71    6.71    6.71    6.71
SO BUILDWID LD5032C-LD7595C    11.23   12.97   14.32   15.46    0.00    0.00
SO BUILDWID LD5032C-LD7595C     0.00    0.00    0.00   14.19   15.16   14.99
SO BUILDWID LD5032C-LD7595C    15.46   15.46   14.99   14.06   11.23    9.14
SO BUILDWID LD5032C-LD7595C    12.71   14.06   14.99   15.46   58.42   61.15
SO BUILDWID LD5032C-LD7595C    28.64   30.02   30.48    0.00    0.00    0.00
SO BUILDWID LD5032C-LD7595C     0.00   15.23   14.32   12.97   11.23    9.14

SO EMISUNIT    .100000E+07 (GRAMS/SEC)         (MICROGRAMS/CUBIC-METER)
SO SRCGROUP BASE32 BASE32A BASE32B BASE32C
SO SRCGROUP BASE95 BASE95A BASE95B BASE95C
SO SRCGROUP LD7532 LD7532A LD7532B LD7532C
SO SRCGROUP LD7595 LD7595A LD7595B LD7595C
SO SRCGROUP LD5032 LD5032A LD5032B LD5032C
SO SRCGROUP LD5095 LD5095A LD5095B LD5095C
SO FINISHED

RE STARTING
RE DISCCART   557000.00 2789000.00
RE DISCCART   556600.00 2792000.00
RE DISCCART   556000.00 2796000.00
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RE DISCCART   553000.00 2796500.00
RE DISCCART   548000.00 2796500.00
RE DISCCART   542700.00 2796500.00
RE DISCCART   542700.00 2800000.00
RE DISCCART   542700.00 2805000.00
RE DISCCART   542700.00 2810000.00
RE DISCCART   542000.00 2811000.00
RE DISCCART   541300.00 2814000.00
RE DISCCART   542700.00 2816000.00
RE DISCCART   544100.00 2820000.00
RE DISCCART   543500.00 2824600.00
RE DISCCART   545000.00 2829000.00
RE DISCCART   545700.00 2832200.00
RE DISCCART   546200.00 2835700.00
RE DISCCART   548600.00 2837500.00
RE DISCCART   550300.00 2839000.00
RE DISCCART   545000.00 2839000.00
RE DISCCART   540000.00 2839000.00
RE DISCCART   550500.00 2844000.00
RE DISCCART   545000.00 2844000.00
RE DISCCART   540000.00 2844000.00
RE DISCCART   550300.00 2848600.00
RE DISCCART   545000.00 2848600.00
RE DISCCART   540000.00 2848600.00
RE DISCCART   535000.00 2848600.00
RE DISCCART   530000.00 2848600.00
RE DISCCART   525000.00 2848600.00
RE DISCCART   520000.00 2848600.00
RE DISCCART   514500.00 2848600.00
RE DISCCART   514500.00 2843000.00
RE DISCCART   514500.00 2838000.00
RE DISCCART   514500.00 2832500.00
RE DISCCART   510000.00 2832500.00
RE DISCCART   505000.00 2832500.00
RE DISCCART   500000.00 2832500.00
RE DISCCART   495000.00 2832500.00
RE DISCCART   494500.00 2837000.00
RE DISCCART   491500.00 2841000.00
RE DISCCART   488500.00 2845500.00
RE DISCCART   483000.00 2848500.00
RE DISCCART   480000.00 2852500.00
RE DISCCART   475000.00 2854000.00
RE DISCCART   473500.00 2857000.00
RE DISCCART   473500.00 2860000.00
RE DISCCART   469000.00 2860000.00
RE DISCCART   464000.00 2860000.00
RE DISCCART   459500.00 2863200.00
RE DISCCART   454000.00 2863200.00
RE FINISHED

ME STARTING
ME INPUTFIL P:\MET\FMYTPA87.ASC
ME ANEMHGHT  20 FEET
ME SURFDATA  12835  1987            FTMYERS
ME UAIRDATA  12842  1987            RUSKIN
ME WINDCATS    1.54     3.09     5.14     8.23     10.80
ME FINISHED


OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
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CO STARTING
CO TITLEONE 1987 IPS DESOTO COUNTY SITE, AT EVERGLADES NP           1/22/00
CO TITLETWO FUEL OIL, GENERIC EMISSION RATES, 3 LOADS AND 2 TEMPERATURES
CO MODELOPT DFAULT CONC   RURAL NOCMPL
CO AVERTIME  PERIOD 24 8 3 1
CO POLLUTID GEN
CO DCAYCOEF    .000000
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
**          SRCID SRCTYP        XS             YS             ZS
** MODELING ORIGIN CT 2 STACK LOCATION
** LOCATION IS USED FOR POLAR DISCRETE RECEPTORS.
**  CT STACK NUMBER CODE
** ------------------------
**  A -  CT 1
**  B -  CT 2
**  C -  CT 3
** Source Location Cards:
**          SRCID SRCTYP      XS        YS        ZS
**   UTM                     (m)       (m)       (m)
SO LOCATION  BASE32A  POINT  419700  3011500    0.0
SO LOCATION  BASE32B  POINT  419700  3011500    0.0
SO LOCATION  BASE32C  POINT  419700  3011500    0.0
SO LOCATION  BASE95A  POINT  419700  3011500    0.0
SO LOCATION  BASE95B  POINT  419700  3011500    0.0
SO LOCATION  BASE95C  POINT  419700  3011500    0.0
SO LOCATION  LD7532A  POINT  419700  3011500    0.0
SO LOCATION  LD7532B  POINT  419700  3011500    0.0
SO LOCATION  LD7532C  POINT  419700  3011500    0.0
SO LOCATION  LD7595A  POINT  419700  3011500    0.0
SO LOCATION  LD7595B  POINT  419700  3011500    0.0
SO LOCATION  LD7595C  POINT  419700  3011500    0.0
SO LOCATION  LD5032A  POINT  419700  3011500    0.0
SO LOCATION  LD5032B  POINT  419700  3011500    0.0
SO LOCATION  LD5032C  POINT  419700  3011500    0.0
SO LOCATION  LD5095A  POINT  419700  3011500    0.0
SO LOCATION  LD5095B  POINT  419700  3011500    0.0
SO LOCATION  LD5095C  POINT  419700  3011500    0.0
** Source Parameter Cards:
** POINT:   SRCID           QS       HS        TS        VS        DS
**                        (g/s)     (m)       (K)      (m/s)      (m)
SO SRCPARAM   BASE32A    3.333    18.3     853.2     37.31     6.71
SO SRCPARAM   BASE32B    3.333    18.3     853.2     37.31     6.71
SO SRCPARAM   BASE32C    3.333    18.3     853.2     37.31     6.71
SO SRCPARAM   BASE95A    3.333    18.3     878.2     35.05     6.71
SO SRCPARAM   BASE95B    3.333    18.3     878.2     35.05     6.71
SO SRCPARAM   BASE95C    3.333    18.3     878.2     35.05     6.71
SO SRCPARAM   LD7532A    3.333    18.3     905.4     30.78     6.71
SO SRCPARAM   LD7532B    3.333    18.3     905.4     30.78     6.71
SO SRCPARAM   LD7532C    3.333    18.3     905.4     30.78     6.71
SO SRCPARAM   LD7595A    3.333    18.3     914.3     29.57     6.71
SO SRCPARAM   LD7595B    3.333    18.3     914.3     29.57     6.71
SO SRCPARAM   LD7595C    3.333    18.3     914.3     29.57     6.71
SO SRCPARAM   LD5032A    3.333    18.3     922.0     26.12     6.71
SO SRCPARAM   LD5032B    3.333    18.3     922.0     26.12     6.71
SO SRCPARAM   LD5032C    3.333    18.3     922.0     26.12     6.71
SO SRCPARAM   LD5095A    3.333    18.3     922.0     24.84     6.71
SO SRCPARAM   LD5095B    3.333    18.3     922.0     24.84     6.71
SO SRCPARAM   LD5095C    3.333    18.3     922.0     24.84     6.71

SO BUILDHGT BASE32A-BASE95A     6.71     6.71     6.71    14.33     0.00     0.00
SO BUILDHGT BASE32A-BASE95A     0.00     0.00     0.00     0.00     0.00     0.00
SO BUILDHGT BASE32A-BASE95A     0.00     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE32A-BASE95A    14.33    14.33    14.33    14.33    14.33    14.33
SO BUILDHGT BASE32A-BASE95A     6.71     6.71     0.00     0.00     0.00     0.00
SO BUILDHGT BASE32A-BASE95A     0.00     6.71     6.71     6.71     6.71     6.71
SO BUILDWID BASE32A-BASE95A    11.23    12.97    14.32    15.46     0.00     0.00
SO BUILDWID BASE32A-BASE95A     0.00     0.00     0.00     0.00     0.00     0.00
SO BUILDWID BASE32A-BASE95A     0.00    15.23    14.32    12.97    11.23     9.14
SO BUILDWID BASE32A-BASE95A    12.71    14.06    14.99    15.46    15.46    14.99
SO BUILDWID BASE32A-BASE95A    15.16    14.19     0.00     0.00     0.00     0.00
SO BUILDWID BASE32A-BASE95A     0.00    15.23    14.32    12.97    11.23     9.14
SO BUILDHGT LD5032A-LD7595A     6.71     6.71     6.71    14.33     0.00     0.00
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SO BUILDHGT LD5032A-LD7595A    0.00   0.00   0.00   0.00   0.00   0.00
SO BUILDHGT LD5032A-LD7595A    0.00   6.71   6.71   6.71   6.71   6.71
SO BUILDHGT LD5032A-LD7595A   14.33  14.33  14.33  14.33  14.33  14.33
SO BUILDHGT LD5032A-LD7595A    6.71   6.71   0.00   0.00   0.00   0.00
SO BUILDHGT LD5032A-LD7595A    0.00   6.71   6.71   6.71   6.71   6.71
SO BUILDWID LD5032A-LD7595A   11.23  12.97  14.32  15.46   0.00   0.00
SO BUILDWID LD5032A-LD7595A    0.00   0.00   0.00   0.00   0.00   0.00
SO BUILDWID LD5032A-LD7595A    0.00  15.23  14.32  12.97  11.23   9.14
SO BUILDWID LD5032A-LD7595A   12.71  14.06  14.99  15.46  15.46  14.99
SO BUILDWID LD5032A-LD7595A   15.16  14.19   0.00   0.00   0.00   0.00
SO BUILDWID LD5032A-LD7595A    0.00  15.23  14.32  12.97  11.23   9.14


SO BUILDHGT BASE32B-BASE95B    6.71   6.71   6.71  14.33   0.00   0.00
SO BUILDHGT BASE32B-BASE95B    0.00   0.00   0.00   6.71   6.71   6.71
SO BUILDHGT BASE32B-BASE95B   14.33  14.33  14.33  14.33   6.71   6.71
SO BUILDHGT BASE32B-BASE95B   14.33  14.33  14.33  14.33  14.33  14.33
SO BUILDHGT BASE32B-BASE95B    6.71   6.71   0.00   0.00   0.00   0.00
SO BUILDHGT BASE32B-BASE95B    0.00   6.71   6.71   6.71   6.71   6.71
SO BUILDWID BASE32B-BASE95B   11.23  12.97  14.32  15.46   0.00   0.00
SO BUILDWID BASE32B-BASE95B    0.00   0.00   0.00  14.19  15.16  15.66
SO BUILDWID BASE32B-BASE95B   15.46  15.46  14.99  14.06  11.23   9.14
SO BUILDWID BASE32B-BASE95B   12.71  14.06  14.99  15.46  15.46  14.99
SO BUILDWID BASE32B-BASE95B   15.16  14.19   0.00   0.00   0.00   0.00
SO BUILDWID BASE32B-BASE95B    0.00  15.23  14.32  12.97  11.23   9.14
SO BUILDHGT LD5032B-LD7595B    6.71   6.71   6.71  14.33   0.00   0.00
SO BUILDHGT LD5032B-LD7595B    0.00   0.00   0.00   6.71   6.71   6.71
SO BUILDHGT LD5032B-LD7595B   14.33  14.33  14.33  14.33   6.71   6.71
SO BUILDHGT LD5032B-LD7595B   14.33  14.33  14.33  14.33  14.33  14.33
SO BUILDHGT LD5032B-LD7595B    6.71   6.71   0.00   0.00   0.00   0.00
SO BUILDHGT LD5032B-LD7595B    0.00   6.71   6.71   6.71   6.71   6.71
SO BUILDWID LD5032B-LD7595B   11.23  12.97  14.32  15.46   0.00   0.00
SO BUILDWID LD5032B-LD7595B    0.00   0.00   0.00  14.19  15.16  15.66
SO BUILDWID LD5032B-LD7595B   15.46  15.46  14.99  14.06  11.23   9.14
SO BUILDWID LD5032B-LD7595B   12.71  14.06  14.99  15.46  15.46  14.99
SO BUILDWID LD5032B-LD7595B   15.16  14.19   0.00   0.00   0.00   0.00
SO BUILDWID LD5032B-LD7595B    0.00  15.23  14.32  12.97  11.23   9.14


SO BUILDHGT BASE32C-BASE95C    6.71   6.71   6.71  14.33   0.00   0.00
SO BUILDHGT BASE32C-BASE95C    0.00   0.00   0.00   6.71   6.71  14.33
SO BUILDHGT BASE32C-BASE95C   14.33  14.33  14.33  14.33   6.71   6.71
SO BUILDHGT BASE32C-BASE95C   14.33  14.33  14.33  14.33  15.24  15.24
SO BUILDHGT BASE32C-BASE95C   15.24  15.24  15.24   0.00   0.00   0.00
SO BUILDHGT BASE32C-BASE95C    0.00   6.71   6.71   6.71   6.71   6.71
SO BUILDWID BASE32C-BASE95C   11.23  12.97  14.32  15.46   0.00   0.00
SO BUILDWID BASE32C-BASE95C    0.00   0.00   0.00  14.19  15.16  14.99
SO BUILDWID BASE32C-BASE95C   15.46  15.46  14.99  14.06  11.23   9.14
SO BUILDWID BASE32C-BASE95C   12.71  14.06  14.99  15.46  58.42  61.15
SO BUILDWID BASE32C-BASE95C   28.64  30.02  30.48   0.00   0.00   0.00
SO BUILDWID BASE32C-BASE95C    0.00  15.23  14.32  12.97  11.23   9.14
SO BUILDHGT LD5032C-LD7595C    6.71   6.71   6.71  14.33   0.00   0.00
SO BUILDHGT LD5032C-LD7595C    0.00   0.00   0.00   6.71   6.71  14.33
SO BUILDHGT LD5032C-LD7595C   14.33  14.33  14.33  14.33   6.71   6.71
SO BUILDHGT LD5032C-LD7595C   14.33  14.33  14.33  14.33  15.24  15.24
SO BUILDHGT LD5032C-LD7595C   15.24  15.24  15.24   0.00   0.00   0.00
SO BUILDHGT LD5032C-LD7595C    0.00   6.71   6.71   6.71   6.71   6.71
SO BUILDWID LD5032C-LD7595C   11.23  12.97  14.32  15.46   0.00   0.00
SO BUILDWID LD5032C-LD7595C    0.00   0.00   0.00  14.19  15.16  14.99
SO BUILDWID LD5032C-LD7595C   15.46  15.46  14.99  14.06  11.23   9.14
SO BUILDWID LD5032C-LD7595C   12.71  14.06  14.99  15.46  58.42  61.15
SO BUILDWID LD5032C-LD7595C   28.64  30.02  30.48   0.00   0.00   0.00
SO BUILDWID LD5032C-LD7595C    0.00  15.23  14.32  12.97  11.23   9.14

SO EMISUNIT    .100000E+07 (GRAMS/SEC)         (MICROGRAMS/CUBIC-METER)
SO SRCGROUP BASE32 BASE32A BASE32B BASE32C
SO SRCGROUP BASE95 BASE95A BASE95B BASE95C
SO SRCGROUP LD7532 LD7532A LD7532B LD7532C
SO SRCGROUP LD7595 LD7595A LD7595B LD7595C
SO SRCGROUP LD5032 LD5032A LD5032B LD5032C
SO SRCGROUP LD5095 LD5095A LD5095B LD5095C
SO FINISHED

RE STARTING
RE DISCCART   557000.00 2789000.00
RE DISCCART   556600.00 2792000.00
RE DISCCART   556000.00 2796000.00
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RE DISCCART   553000.00 2796500.00
RE DISCCART   548000.00 2796500.00
RE DISCCART   542700.00 2796500.00
RE DISCCART   542700.00 2800000.00
RE DISCCART   542700.00 2805000.00
RE DISCCART   542700.00 2810000.00
RE DISCCART   542000.00 2811000.00
RE DISCCART   541300.00 2814000.00
RE DISCCART   542700.00 2816000.00
RE DISCCART   544100.00 2820000.00
RE DISCCART   543500.00 2824600.00
RE DISCCART   545000.00 2829000.00
RE DISCCART   545700.00 2832200.00
RE DISCCART   546200.00 2835700.00
RE DISCCART   548600.00 2837500.00
RE DISCCART   550300.00 2839000.00
RE DISCCART   545000.00 2839000.00
RE DISCCART   540000.00 2839000.00
RE DISCCART   550500.00 2844000.00
RE DISCCART   545000.00 2844000.00
RE DISCCART   540000.00 2844000.00
RE DISCCART   550300.00 2848600.00
RE DISCCART   545000.00 2848600.00
RE DISCCART   540000.00 2848600.00
RE DISCCART   535000.00 2848600.00
RE DISCCART   530000.00 2848600.00
RE DISCCART   525000.00 2848600.00
RE DISCCART   520000.00 2848600.00
RE DISCCART   514500.00 2848600.00
RE DISCCART   514500.00 2843000.00
RE DISCCART   514500.00 2838000.00
RE DISCCART   514500.00 2832500.00
RE DISCCART   510000.00 2832500.00
RE DISCCART   505000.00 2832500.00
RE DISCCART   500000.00 2832500.00
RE DISCCART   495000.00 2832500.00
RE DISCCART   494500.00 2837000.00
RE DISCCART   491500.00 2841000.00
RE DISCCART   488500.00 2845500.00
RE DISCCART   483000.00 2848500.00
RE DISCCART   480000.00 2852500.00
RE DISCCART   475000.00 2854000.00
RE DISCCART   473500.00 2857000.00
RE DISCCART   473500.00 2860000.00
RE DISCCART   469000.00 2860000.00
RE DISCCART   464000.00 2860000.00
RE DISCCART   459500.00 2863200.00
RE DISCCART   454000.00 2863200.00
RE FINISHED

ME STARTING
ME INPUTFIL P:\MET\FMYTPA87.ASC
ME ANEMHGHT  20 FEET
ME SURFDATA  12835  1987            FTMYERS
ME UAIRDATA  12842  1987            RUSKIN
ME WINDCATS    1.54     3.09     5.14     8.23    10.80
ME FINISHED


OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
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