Florida Power
A Progress Energy Company

Supplemental
Site Certification Application

Hines Energy Complex

Power Block 3

September 2002

Volume 2

RECEIVED
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BUREAU OF AIR REGULATION

SUPPLEMENTAL SITE CERTIFICATION

FOR THE

FLORIDA POWER

HINES ENERGY COMPLEX

POWER BLOCK 3

POLK COUNTY, FLORIDA

VOLUME II OF II

SEPTEMBER 2002

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SECTION 10

10.0 APPENDICES

10.1 FEDERAL PERMIT APPLICATIONS OR APPROVALS

10.1.1 316 Demonstrations

There is no surface water intake or point source thermal discharge to surface waters located at the Hines Energy Complex. Therefore, no demonstrations pursuant to Sections 316(a) or (b) of the Clean Water Act are required. This section is not applicable.

10.1.2 NPDES Application/Permit

The Hines Energy Complex will operate as a zero discharge facility for industrial wastewaters. Therefore, no NPDES permit or permit application will be required for operation of the Power Blocks. This section is not applicable.

10.1.3 Hazardous Waste Management Application/Permit

The Hines Energy Complex has been designed to operate so that a federal or state hazardous waste treatment, storage or disposal permit is not required. This section is not applicable.

10.1.4 Section 10 or 404 Application/Permit

A copy of the U.S. Army Corps of Engineers (COE) Permit No. 199302169 (IP-MN) previously issued is available upon request.

10.1.5 Prevention of Significant Deterioration Permit Application

Following is a copy of the Prevention of Significant Deterioration (PSD) permit application for Power Block 3 submitted to the DEP pursuant to requirements of the Federal Clean Air Act.

PSD PERMIT APPLICATION

FOR

FLORIDA POWER
HINES ENERGY COMPLEX
POWER BLOCK 3

September 2002

Florida Power
One Power Plaza
263 13th Ave. South
St. Petersburg, Florida 33701

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APPLICATION FORMS

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name:
Florida Power

2. Site Name:
Hines Energy Complex

3. Facility Identification Number: [X] Unknown

4. Facility Location:
Street Address or Other Locator: **7700 County Road 555**
City: **Bartow** County: **Polk** Zip Code: **33830**

5. Relocatable Facility?
[ ] Yes [X] No

6. Existing Permitted Facility?
[X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact:
Jamie Hunter, Lead Environmental Specialist

2. Application Contact Mailing Address:
Organization/Firm: **Florida Power**
Street Address: **P.O. Box 14042, MAC BB1A**
City: **St. Petersburg** State: **FL** Zip Code: **33733-4042**

3. Application Contact Telephone Numbers:
Telephone: (**727**) **826 - 4363** Fax: (**727**) **826 - 4216**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	9-4-02
2. Permit Number:	1050234-006-AC
3. PSD Number (if applicable):	PSD-FL-330
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:
Bruce Baldwin, Vice President – Combustion Turbine Operations

2. Owner/Authorized Representative or Responsible Official Mailing Address:
Organization/Firm: **Florida Power**
Street Address: **P.O. Box 14042, MAC BB1C**
City: **St. Petersburg** State: **FL** Zip Code: **33733-4042**

3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
Telephone: **(813) 826- 4201** Fax: **(813) 826- 4222**

4. Owner/Authorized Representative or Responsible Official Statement:

I, the undersigned, am the owner or authorized representative(check here [X], 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.*

Signature

8-30-02
Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: **Kennard F. Kosky**
Registration Number: **14996**

2. Professional Engineer Mailing Address:
Organization/Firm: **Golder Associates Inc.**
Street Address: **6241 NW 23rd Street, Suite 500**
City: **Gainesville** State: **FL** Zip Code: **32653-1500**

3. Professional Engineer Telephone Numbers:
Telephone: **(352) 336 - 5600** Fax: **(352) 336 - 6603**

4. Professional Engineer Statement:

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

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

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

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

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

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

Signature

August 30, 2002
Date

(seal)

* Attach any exception to certification statement.

Golder Associates - Board of Professional Engineers
Certificate of Authorization Number 00001670

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
---	CT- 3a; Power Block 3	AC1A	
---	CT- 3b; Power Block 3	AC1A	

Application Processing Fee

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

Construction/Modification Information

1. Description of Proposed Project or Alterations:

Power Block 3 consists of two nominal 170 MW Siemens Westinghouse 501FD combustion turbines (CTs), two unfired heat recovery steam generators (HRSGs), and one 190 MW steam turbine; nominal rating of 530 MW combined cycle unit. See PSD Application. Fee included with Site Certification Application.

2. Projected or Actual Date of Commencement of Construction: **November, 2003**

3. Projected Date of Completion of Construction: **November, 2005**

Application Comment

This application has been submitted and will be reviewed within the Florida Power Plant Siting Act (PPSA). See PSD Application. Power Block 1 has permit PA-92-33; PSD-FL-195A. Power Block 2 has permit PA92-33SA, PSD-FL-296.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates:
Zone: **17** East (km): **414.4** North (km): **3073.9**

2. Facility Latitude/Longitude:
Latitude (DD/MM/SS): **27 / 47 / 19** Longitude (DD/MM/SS): **81 / 52 / 10**

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):

Operation of Power Block 1 began in 1999. Power Block 1 is a nominal 470 MW combined cycle unit consisting of 2 CTs, 2 HRSGs and 1 steam turbine. The CTs fire natural gas with distillate oil as backup. The HRSGs are unfired. Power Block 2 is a nominal 530 MW combined-cycle unit consisting of 2 CTs, 2 HRSGs, and 1 steam turbine. This application is for the addition of Power Block 3, an additional nominal 530 MW combined-cycle application. See PSD Application.

Facility Contact

1. Name and Title of Facility Contact:
Roger Zirkle, Plant Manager

2. Facility Contact Mailing Address:
Organization/Firm: **Hines Energy Complex**
Street Address: **7700 County Road 555**
City: **Bartow** State: **FL** Zip Code: **33830**

3. Facility Contact Telephone Numbers:
Telephone: **(863) 519 - 6103** Fax: **(863) 519 - 6110**

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. [ ] Title V Source by EPA Designation?
9. Facility Regulatory Classifications Comment (limit to 200 characters):

Applicable NSPS is 40 CFR Part 60; Subpart GG.

List of Applicable Regulations

62-212.400, F.A.C. See PSD Application	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap		4. Basis for Emissions Cap	5. Pollutant Comment
		lb/hour	tons/year		
PM	**A**				**Particulate Matter – Total**
SO_2	**A**				**Sulfur Dioxide**
NO_X	**A**				**Nitrogen Oxides**
CO	**A**				**Carbon Monoxide**
VOC	**A**				**Volatile Organic Compounds**
SAM	**B**				**Sulfuric Acid Mist**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location:
[X] Attached, Document ID: Fig. 1-1; PSD [ ] Not Applicable [ ] Waiver Requested

2. Facility Plot Plan:
[X] Attached, Document ID: Fig. 2-1; PSD [ ] Not Applicable [ ] Waiver Requested

3. Process Flow Diagram(s):
[X] Attached, Document ID: Fig. 2-2; PSD [ ] Not Applicable [ ] Waiver Requested

4. Precautions to Prevent Emissions of Unconfined Particulate Matter:
[X] Attached, Document ID: PSD Appl. [ ] 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 Appl. [ ] 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):

CT-3A; Power Block 3

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

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

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

Siemens Westinghouse 501 FD combustion turbine firing natural gas with distillate oil back-up.

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

Selective Catalytic Reduction (SCR) – natural gas firing/ distillate oil firing.

Water Injection – distillate oil firing

2. Control Device or Method Code(s): **25, 65, 28**

Emissions Unit Details

1. Package Unit:
   Manufacturer: **Siemens Westinghouse** Model Number: **501 FD**

2. Generator Nameplate Rating: **170** 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:		**1,830**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**8,760**	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Heat input is HHV with natural gas; heat input at 59°F turbine inlet temperature; MW nominal rating.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment HEC-EU1-C	
See PSD Application	

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? **Fig 2-1**

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: **125** feet

7. Exit Diameter: **19** feet

8. Exit Temperature: **190** °F

9. Actual Volumetric Flow Rate: **1,009,487** acfm

10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm

12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **414.4** North (km): **3073.9**

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

Temperature and flow for natural gas at 59°F turbine inlet; See Tables 2-1 and 2-2 in PSD application.

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): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.92**	5. Maximum Annual Rate: **15,564**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,030**
10. Segment Comment (limit to 200 characters): **Based on 1,030 BTU/CF (HHV); maximum hourly at 20°F; annual at 59°F; turbine inlet temperatures.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 Gallons Used**	
4. Maximum Hourly Rate: **14.9**	5. Maximum Annual Rate: **13,683**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **141.2**
10. Segment Comment (limit to 200 characters): **BTU based on HHV of 141.2 MMBtu/1,000 gallons. Aggregate fuel usage of 27,365,000 gallons per year requested for Power Block 3.**		

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			
SO_2			
NO_X	025, 028	065	EL
CO			EL
VOC			EL
SAM			

Emissions Unit Information Section 1 of 2 CT-3A– Power Block 3

Pollutant Detail Information Page 1 of 6 Particulate Matter - Total

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: **64.8** lb/hour **60.3** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Section 2.0 and Appendix A in PSD Application**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

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: **10 % Opacity**	4. Equivalent Allowable Emissions: **8.5** lb/hour **34.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 9; Initially and Annually.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Emissions Unit Information Section 1 **of** 2 CT-3A– Power Block 3

Pollutant Detail Information Page 1 **of** 6 Particulate Matter - Total

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: lb/hour tons/year
4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions:
   [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference:
7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

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:
   20% Opacity
4. Equivalent Allowable Emissions:
   64.8 lb/hour **29.8** tons/year
5. Method of Compliance (limit to 60 characters):
   EPA Method 9; When oil firing greater than 400 hrs/year.
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
   Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.

Emissions Unit Information Section 1 **of** 2 CT-3A– Power Block 3

Pollutant Detail Information Page 2 **of** 6 Sulfur Dioxide

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: **105.6** lb/hour **68.4** tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor:
Reference: **Siemens Westinghouse, 2000**

7. Emissions Method Code: **2**

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

See Section 2.0 and Appendix A in PSD Application

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

Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.

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: **Natural Gas**

4. Equivalent Allowable Emissions: **5.5** lb/hour **22.4** tons/year

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

Fuel Sampling – Vendor or Applicant

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

Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.

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: lb/hour tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor:
Reference:

7. Emissions Method Code:

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

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

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: **0.05 % Sulfur Oil**

4. Equivalent Allowable Emissions: **105.6** lb/hour **48.6** tons/year

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

Fuel Sampling – Vendor or Applicant

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

Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.

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: **92.3** lb/hour **133.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 1998**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Maximum lb/hour based on oil-firing. See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

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: **3.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **25.0** lb/hour **101.2** tons/year
5. Method of Compliance (limit to 60 characters): **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Emissions Unit Information Section 1 of 2 **CT-3A – Power Block 3**

Pollutant Detail Information Page 3 of 6 **Nitrogen Oxides**

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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 @ 15% O_2**	4. Equivalent Allowable Emissions: **92.3** lb/hour **44** tons/year
5. Method of Compliance (limit to 60 characters): **CEM; Part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Emissions Unit Information Section 1 of 2 **CT-3A – Power Block 3**

Pollutant Detail Information Page 4 of 6 **Carbon Monoxide**

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: **154** lb/hour **372** tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor:
Reference: **Siemens Westinghouse, 2000**

7. Emissions Method Code: **2**

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

See Section 2.0 and Appendix A in PSD Application

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

Max lb/hr for gas firing at 60% load and 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas includes 3,000 hrs at 60% load; equivalent of 1,000 hrs/yr/CT-oil.

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:
10 ppmvd – Base Load/50 ppmvd at 60% load

4. Equivalent Allowable Emissions:
154 lb/hour **340** tons/year

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

EPA Method 10 @ 15% O_2

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

Gas Firing: lb/hr at 20°F turbine inlet 60% load; TPY for 5,760 hrs/yr (100% load) and 3,000 hours (60% load) at 59°F turbine inlet.

Emissions Unit Information Section 1 of 2 **CT-3A – Power Block 3**

Pollutant Detail Information Page 4 of 6 **Carbon Monoxide**

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: lb/hour tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor:
   Reference:

7. Emissions Method Code:

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

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

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: **30 ppmvd**

4. Equivalent Allowable Emissions: **112** lb/hour **53** tons/year

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

   EPA Method 10; Initial and Annual at Base Load

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

   Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.

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: **22** lb/hour **28.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Section 2.0 and Appendix A in PSD Application**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas (100% and 60% loads); equivalent of 1,000 hrs/yr/CT-oil.**	

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: **1.8 ppmvd – Baseload/ 3 ppmvd – 60% load**	4. Equivalent Allowable Emissions: **5.3** lb/hour **20** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; at 15% O_2**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 60% load 20°F turbine inlet; TPY for 5,760 hrs/yr (100% load) and 3,000 hrs (60% load) at 59°F turbine inlet.**	

Emissions Unit Information Section 1 of 2 CT-3A – Power Block 3

Pollutant Detail Information Page 5 of 6 Volatile Organic Compounds

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: lb/hour tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor:

Reference:

7. Emissions Method Code:

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

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

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 ppmvw**

4. Equivalent Allowable Emissions: **22** lb/hour **10.5** tons/year

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

EPA Method 25A

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

Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **16.2** lb/hour **10.5** tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor: **10 % SO_2**

   Reference: **Golder, 2000**

7. Emissions Method Code: **2**

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

   Emission Factor is converted to SAM. See Section 2.0 and Appendix A in PSD Application.

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

   Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.

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: **Natural Gas**

4. Equivalent Allowable Emissions: **0.9** lb/hour **3.4** tons/year

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

   Fuel Sampling – Vendor or Applicant

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

   Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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: **0.05 % Sulfur oil**	4. Equivalent Allowable Emissions: **16.2** lb/hour **7.44** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling – Vendor or Applicant**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**

2. Basis for Allowable Opacity: [ ] Rule [X] Other

3. Requested Allowable Opacity:
Normal Conditions: **10** % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:
EPA Method 9.

5. Visible Emissions Comment (limit to 200 characters):

Gas 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:
Manufacturer: **Not Yet Determined**
Model Number: Serial Number:

5. Installation Date:

6. Performance Specification Test Date:

7. Continuous Monitor Comment (limit to 200 characters):

NO_X **CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [ ] Rule [X] Other

3. Requested Allowable Opacity:
Normal Conditions: **20** % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

EPA Method 9.

5. Visible Emissions Comment (limit to 200 characters):

Oil Firing

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement:	[X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **Siemens Westinghouse**
Model Number: Serial Number:

5. Installation Date:	6. Performance Specification Test Date:

7. Continuous Monitor Comment (limit to 200 characters):

Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request Part 75 NO_X CEM in lieu of WTF monitoring

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

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

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: **60** min/hour

4. Method of Compliance:

   None

5. Visible Emissions Comment (limit to 200 characters):

   FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown and malfunction.

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

Continuous Monitoring System: Continuous Monitor ______ of______

1. Parameter Code:

2. Pollutant(s):

3. CMS Requirement: [ ] Rule [ ] Other

4. Monitor Information:
   Manufacturer:
   Model Number: Serial Number:

5. Installation Date:

6. Performance Specification Test Date:

7. Continuous Monitor Comment (limit to 200 characters):

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

Supplemental Requirements

1. Process Flow Diagram
[X] Attached, Document ID: Fig 2-2 [ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification
[X] Attached, Document ID: Tab 2-4/2-5 [ ] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment
[X] Attached, Document ID: Sec 4.0 [ ] Not Applicable [ ] Waiver Requested

4. Description of Stack Sampling Facilities
[X] Attached, Document ID: PSD Appl. [ ] 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 Appl. [ ] Not Applicable

9. Other Information Required by Rule or Statute
[X] Attached, Document ID: PSD Appl. [ ] 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):

CT- 3b; Power Block 3

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

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

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

Siemens Westinghouse 501 FD combustion turbine firing natural gas with distillate oil back-up.

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

Selective Catalytic Reduction (SCR) – natural gas firing/ distillate oil firing.

Water Injection – distillate oil firing

2. Control Device or Method Code(s): **25, 65, 28**

Emissions Unit Details

1. Package Unit:
   Manufacturer: **Siemens Westinghouse** Model Number: **501 FD**

2. Generator Nameplate Rating: **170** 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:		**1,830**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**8,760**	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Heat input is HHV with natural gas; heat input at 59°F turbine inlet temperature; MW nominal rating.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment HEC-EU1-C	
See PSD Application	

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? **Fig 2-1**	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: **125** feet	7. Exit Diameter: **19** feet
8. Exit Temperature: **190** °F	9. Actual Volumetric Flow Rate: **1,009,487** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: **17** East (km): **414.4** North (km): **3073.9**		
14. Emission Point Comment (limit to 200 characters): **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 2-1 and 2-2 in PSD application.**		

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):

Natural Gas

2. Source Classification Code (SCC): **2-01-002-01**

3. SCC Units: **Million Cubic Feet**

4. Maximum Hourly Rate: **1.92**

5. Maximum Annual Rate: **15,564**

6. Estimated Annual Activity Factor:

7. Maximum % Sulfur:

8. Maximum % Ash:

9. Million Btu per SCC Unit: **1,030**

10. Segment Comment (limit to 200 characters):

Based on 1,030 BTU/CF (HHV); maximum hourly at 20°F; annual at 59°F; turbine inlet temperatures.

Segment Description and Rate: Segment 2 of 2

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

Distillate Fuel Oil

2. Source Classification Code (SCC): **2-01-001-01**

3. SCC Units: **1,000 Gallons Used**

4. Maximum Hourly Rate: **14.9**

5. Maximum Annual Rate: **13,683**

6. Estimated Annual Activity Factor:

7. Maximum % Sulfur:

8. Maximum % Ash:

9. Million Btu per SCC Unit: **141.2**

10. Segment Comment (limit to 200 characters):

BTU based on HHV of 141.2 MMBtu/1,000 gallons. Aggregate fuel usage of 27,365,000 gallons per year requested for Power Block 3.

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			
SO_2			
NO_X	025, 028	065	EL
CO			EL
VOC			EL
SAM			

Emissions Unit Information Section 2 of 2 **CT-3B – Power Block 3**

Pollutant Detail Information Page 1 of 6 **Particulate Matter - Total**

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: **64.8** lb/hour **60.3** tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor:
Reference: **Siemens Westinghouse, 2000**

7. Emissions Method Code: **2**

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

See Section 2.0 and Appendix A in PSD Application

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

Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.

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: **10 % Opacity**

4. Equivalent Allowable Emissions: **8.5** lb/hour **34.0** tons/year

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

EPA Method 9; Initially and Annually

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

Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.

Emissions Unit Information Section 2 of 2 **CT-3B – Power Block 3**

Pollutant Detail Information Page 1 of 6 **Particulate Matter - Total**

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: lb/hour tons/year
4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference:
7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

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: **20% Opacity**
4. Equivalent Allowable Emissions: **64.8** lb/hour **29.8** tons/year
5. Method of Compliance (limit to 60 characters):

   EPA Method 9; When oil firing is greater than 400 hrs/year
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.

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: **105.6** lb/hour **68.4** tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor:
Reference: **Siemens Westinghouse, 2000**

7. Emissions Method Code: **2**

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

See Section 2.0 and Appendix A in PSD Application

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

Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.

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:
Natural Gas

4. Equivalent Allowable Emissions:
5.5 lb/hour **22.4** tons/year

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

Fuel Sampling – Vendor or Applicant

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

Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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: **0.05 % Sulfur Oil**	4. Equivalent Allowable Emissions: **105.6** lb/hour **48.6** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling – Vendor or Applicant**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

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: **92.3** lb/hour **133.4** tons/year
4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:
   Reference: **Siemens Westinghouse, 1998**
7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):

   Maximum lb/hour based on oil-firing. See Section 2.0 and Appendix A in PSD Application.
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.

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: **3.5 ppmvd at 15% O_2**
4. Equivalent Allowable Emissions: **25.0** lb/hour **101.2** tons/year
5. Method of Compliance (limit to 60 characters):

   CEM; part 75; 24-hour block average; midnight to midnight
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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 @ 15% O_2**	4. Equivalent Allowable Emissions: **92.3** lb/hour **44** tons/year
5. Method of Compliance (limit to 60 characters): **CEM; Part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

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: **154** lb/hour **372** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Section 2.0 and Appendix A in PSD Application**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for gas firing at 60% load and 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas includes 3,000 hrs at 60% load; equivalent of 1,000 hrs/yr/CT-oil.**	

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: **10 ppmvd – Base Load/50 ppmvd at 60% load**	4. Equivalent Allowable Emissions: **154** lb/hour **340** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10 @ 15% O_2**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 20°F turbine inlet 60% load; TPY for 5,760 hrs/yr (100% load) and 3,000 hours (60% load) at 59°F turbine inlet.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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: **30 ppmvd**	4. Equivalent Allowable Emissions: **112** lb/hour **53** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Emissions Unit Information Section 2 of 2 — CT-3B – Power Block 3

Pollutant Detail Information Page 5 of 6 — Volatile Organic Compounds

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: **22** lb/hour **28.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Section 2.0 and Appendix A in PSD Application**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas (100% and 60% loads); equivalent of 1,000 hrs/yr/CT-oil.**	

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: **1.8 ppmvd – Baseload/ 3 ppmvd – 60% load**	4. Equivalent Allowable Emissions: **5.3** lb/hour **20** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; at 15% O_2**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 60% load 20°F turbine inlet; TPY for 5,760 hrs/yr (100% load) and 3,000 hrs (60% load) at 59°F turbine inlet.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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 ppmvw**	4. Equivalent Allowable Emissions: **22** lb/hour **10.5** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Emissions Unit Information Section 2 of 2 **CT-3B – Power Block 3**

Pollutant Detail Information Page 6 of 6 **Sulfuric Acid Mist**

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **16.2** lb/hour **10.5** tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor: **10 % SO_2**

   Reference: **Golder, 2000**

7. Emissions Method Code: **2**

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

   Emission Factor is converted to SAM. See Section 2.0 and Appendix A in PSD Application.

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

   Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.

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: **Natural Gas**

4. Equivalent Allowable Emissions: **0.9** lb/hour **3.4** tons/year

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

   Fuel Sampling – Vendor or Applicant

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

   Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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: **0.05 % Sulfur oil**	4. Equivalent Allowable Emissions: **16.2** lb/hour **7.44** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling – Vendor or Applicant**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype:
VE10

2. Basis for Allowable Opacity:
[ ] Rule [X] Other

3. Requested Allowable Opacity:
Normal Conditions: **10** % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

EPA Method 9.

5. Visible Emissions Comment (limit to 200 characters):

Gas 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:
Manufacturer: **Not Yet Determined**
Model Number: Serial Number:

5. Installation Date:

6. Performance Specification Test Date:

7. Continuous Monitor Comment (limit to 200 characters):

NO_X CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [ ] Rule [X] Other

3. Requested Allowable Opacity:
Normal Conditions: 20 % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

EPA Method 9.

5. Visible Emissions Comment (limit to 200 characters):

Oil Firing

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement:	[X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **Siemens Westinghouse**
Model Number: Serial Number:

5. Installation Date:	6. Performance Specification Test Date:

7. Continuous Monitor Comment (limit to 200 characters):

Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request NO_X CEM in lieu of WTF monitoring

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

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

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: **60** min/hour

4. Method of Compliance:

None

5. Visible Emissions Comment (limit to 200 characters):

FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown and malfunction.

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

Continuous Monitoring System: Continuous Monitor ______ of______

1. Parameter Code:	2. Pollutant(s):

3. CMS Requirement: [ ] Rule [ ] Other

4. Monitor Information:
Manufacturer:
Model Number: Serial Number:

5. Installation Date:	6. Performance Specification Test Date:

7. Continuous Monitor Comment (limit to 200 characters):

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

Supplemental Requirements

1. Process Flow Diagram
   [X] Attached, Document ID: Fig 2-2 [ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification
   [X] Attached, Document ID: Tab 2-4/2-5 [ ] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment
   [X] Attached, Document ID: Sec 4.0 [ ] Not Applicable [ ] Waiver Requested

4. Description of Stack Sampling Facilities
   [X] Attached, Document ID: PSD Appl. [ ] 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 Appl. [ ] Not Applicable

9. Other Information Required by Rule or Statute
   [X] Attached, Document ID: PSD Appl. [ ] 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

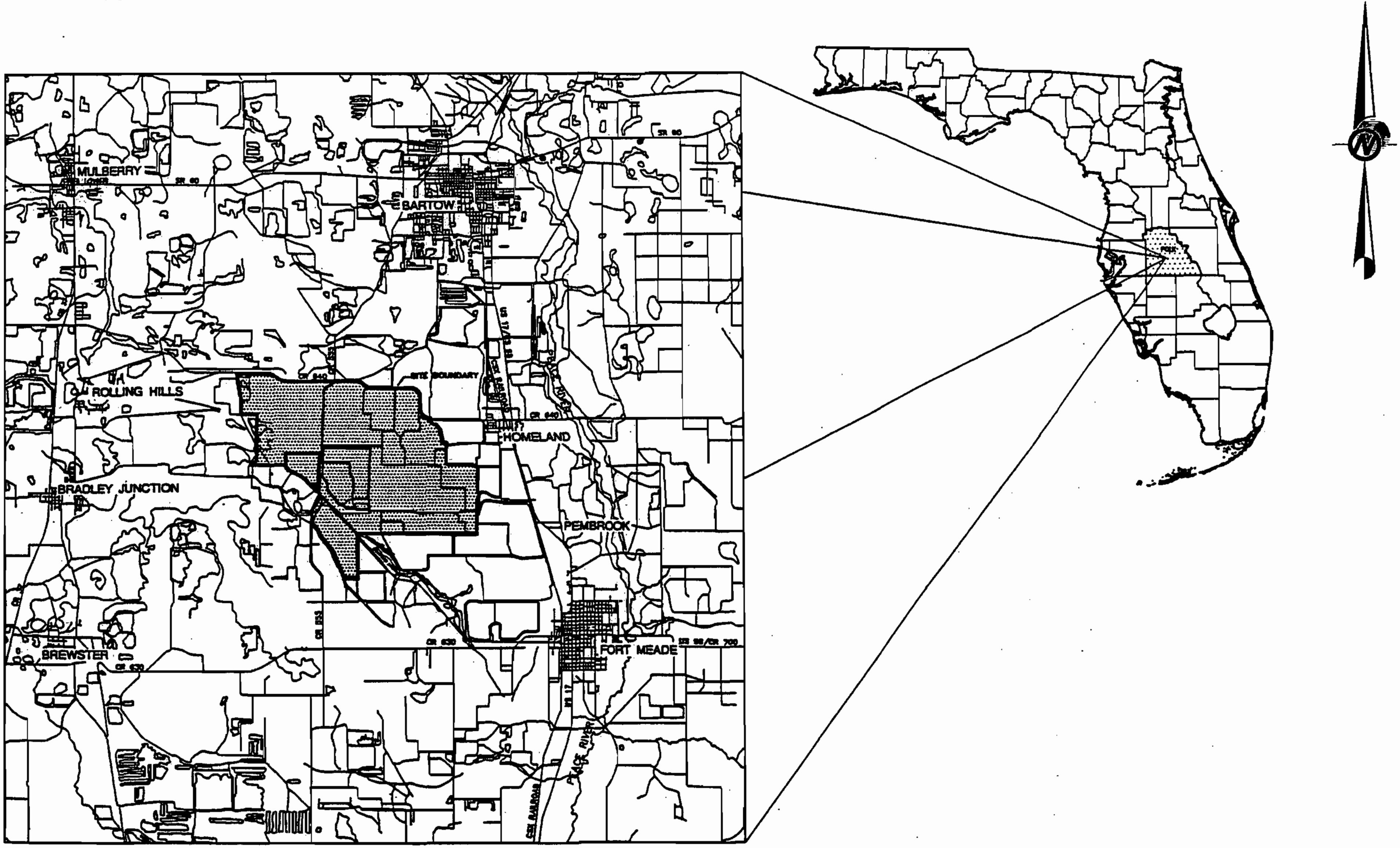
1.0 INTRODUCTION

Florida Power (FP) is the owner and operator of the Hines Energy Complex which is located in the southwest portion of Polk County, about seven miles south-southwest of Bartow and five miles west-northwest of Fort Meade (see Figure 1-1). Currently in operation is Power Block 1, consisting of one 485 MW (MW-nominal 500 MW) combined cycle (CC) power generation unit. Power Block 2 is a 530 MW CC power generation unit and is currently under construction. The expansion of generating capacity at the Hines Energy Complex will be accomplished by using the most efficient generation technology throughout the life of the project. This approach offers Florida Power's maximum flexibility and cost control as both technology and electrical demand increases.

Power Block 3 (the Project) consists of two nominal 170 MW Siemens Westinghouse 501 FD combustion turbines (CTs), two unfired heat recovery steam generators (HRSGs), and one nominal 190 MW steam turbine generator (STG); i.e., a two-on-one configuration. The total nominal rating for Power Block 3 is approximately 530 MW. Pipeline quality natural gas will be utilized as the primary fuel with limited use of low sulfur fuel oil as the back-up fuel. Among the advantages of this CC technology are its fuel flexibility, modularity, and efficiency.

The U.S. Environmental Protection Agency (EPA) has promulgated Prevention of Significant Deterioration (PSD) regulations (40 CFR 52.21), which require a permit review and approval for new or modified sources that increase air pollutant emissions above specified threshold levels. These emission threshold levels will be exceeded for several criteria pollutants during operation of Power Block 3. As a result, Power Block 3 is subject to PSD review for these pollutants. The Federal PSD regulations are implemented in Florida by the Florida Department of Environmental Protection (FDEP). FDEP's PSD regulations are codified in Rule 62-212.400 F.A.C. The technical information and analysis required by the federal and state PSD regulations are contained in this PSD permit application. Although this document will be an appendix to the Site Certification Application (SCA) and only addresses Power Block 3, it has been prepared as a stand-alone PSD permit application. The permit application is divided into eight major sections. Presented in Section 2.0 is a description of the facility, including air pollutant emissions and stack parameters. Air quality review requirements and applicability are presented in Section 3.0. The best available control technology (BACT) evaluation is presented in Section 4.0. An ambient air quality monitoring data analysis is presented in Section 5.0, and the air quality modeling methodology, the results of the air quality impact assessment, and additional impacts analysis performed for the proposed project are presented in Sections 6.0, 7.0, and 8.0, respectively. Section 9.0 contains a list of references and materials cited.

Drawing file: 0237539A059 fig 1_1.dwg Aug 27, 2002 - 3:59pm



SOURCE: 1992 SCA

Florida Power
A Progress Energy Company

Hines Energy Complex

FIGURE 1-1
SITE LOCATION MAP

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

The proposed Power Block 3 project will consist of the construction of approximately 530 MW of generation. The CC configuration consists of two CTs, two HRSGs, and one steam turbine. In this "two-on-one" configuration, each of the two CTs are nominally rated at 170 MW, and the steam turbine has a nominal rating of 190 MW. Each CT will be served by a single HRSG, exhausting to an individual stack. There will be no HRSG bypass stacks for simple cycle operation. Also, there will be no supplemental firing of the HRSGs. The expected primary fuel is natural gas, with low sulfur fuel oil as a backup.

The CC units will utilize low sulfur fuel to limit sulfur dioxide (SO_2) emissions and sulfuric acid mist, selective catalytic reduction (SCR) to limit emissions of oxides of nitrogen (NO_X), and good combustion practices and clean fuels for the minimization of particulate matter (PM/PM_{10}), carbon monoxide (CO), volatile organic compounds (VOCs), and other (trace metals) emissions. The proposed emission control techniques are described in detail in Section 4.0 of this application.

2.2 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

As the steam turbine is not a combustion source, estimated mass emissions are based on operation of only the CTs. However, the exhaust gas characteristics reflect flow through the HRSG (i.e., the characteristics reflect the impact of the steam turbine). Therefore, the estimated stack emissions that are representative of the advanced CT designs proposed for Power Block 3 are presented in Tables 2-1 and 2-2 for a 170 MW CT unit (refer to Appendix A for detailed turbine performance and emissions data). The exhaust parameters presented in these tables are reflective of the combined cycle configuration. These tables cover the natural gas and fuel oil cases for three compressor inlet temperatures: 1) the high temperature case of 105°F for oil and 90°F for gas, 2) the ISO reference temperature case of 59°F and 3) the low temperature case that represents the shaft limit or the maximum physical output of the equipment, i.e., 20°F for oil/natural gas. Maximum hourly emission rates for all pollutants, in units of pounds per hour (lb/hr) are projected to occur for operations at low compressor inlet temperature and base (100 percent) load operation. Maximum annual potential emission rates (after the application of BACT) for the proposed sources with respect to regulated criteria air pollutants and regulated non-criteria air pollutants are presented in Table 2-3.

Worst-case air quality impacts due to the proposed facility are a function of emission rate and plume rise. A number of operating cases (combinations of operating conditions and fuel types) were examined to represent the range that will occur during actual operations. The low (20°F) and high (105°F oil/90°F gas) compressor inlet temperatures and a range of loads (100 to 60 percent for natural gas and 100 to 65 percent for oil) represent the range of combustion turbine performance and emissions/exhaust characteristics that will occur during normal operation. At high compressor inlet temperatures, the units cannot generate as much power because of lower inlet air density. To compensate for a portion of the loss of output (which can be on the order of 20 MW compared to referenced temperatures), inlet cooling is proposed to be installed ahead of the combustion turbine inlet. Therefore, the 59°F temperature case represents a conservative average temperature condition for estimating annual emissions for Power Block 3, inclusive of potential inlet cooling.

Since the performance of the CTs might be slightly higher than the design criteria, FP requests permit maximum heat input rates equivalent to those permitted for Power Block 2. The requested maximum heat input rates, based on the higher heating valve of fuels, and an ambient temperature of 59°F are 1915 mmBTU/hr when firing natural gas and 2020 mmBTU/hr when firing distillate fuel oil.

A review of the CT unit design information in Tables 2-1 and 2-2 indicates that the highest criteria air pollutant emission rates for SO_2, PM/PM_{10}, NO_X, CO, and VOCs occur when burning fuel oil. Combustion of fuel oil also results in higher exhaust gas flow rates and stack exit temperatures, which are directly related to plume rise. Although the highest emission rates occur under the low compressor inlet temperature (20°F) condition, the lowest exhaust gas volumetric flow rate for the CC units occurs under the 105°F ambient temperature condition. Detailed discussion on the determination of worst-case impacts is presented in Section 6.0 (Air Quality Modeling Methodology).

Typical fuel analyses for natural gas and fuel oil are presented in Tables 2-4 and 2-5, respectively. For oil firing, it is requested that an aggregate annual fuel usage for Power Block 3 of 27,365,000 gallons be included as a permit condition. This equates to a maximum of 1,000 hours per year per turbine of generation at full load (59° F).

2.3 SITE LAYOUT AND STRUCTURES

The site arrangement for Power Block 3 as well as existing Power Blocks 1 and 2 is depicted in Figure 2-1. Each power block consists of two CTs, two HRSGs, and one steam turbine. The six HRSG stacks are arranged in an east-west line. The flow diagram for a CC unit is depicted in Figure 2-2. Stack sampling facilities will be constructed in accordance with Rule 62-297.310(6) F.A.C.

TABLE 2-1
COMBUSTION TURBINE UNIT (170 MW)
ESTIMATED (1) PERFORMANCE ON NATURAL GAS

CONDITIONS			
Ambient Temperature (°F)	20	59	90
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	100	100	100
Maximum Heat Input Rate (MMBtu/hr)(2)	2,012	1,830	1,705
EMISSIONS (lb/hr)			
Carbon Monoxide (10 ppm at 15% O_2)	46	42	37
Nitrogen Oxides (3.5 ppmvd at 15% O_2)(3)	25.0	23.1	21.2
Sulfur Dioxide	5.6	5.1	4.8
Particulate Matter (PM_{10})	8.5	7.9	7.2
Opacity (%)	10	10	10
VOCs (1.8 ppmvd at 15% O_2)	4.7	4.4	3.8
Lead	Neg.	Neg.	Neg.
Sulfuric Acid Mist	0.9	0.8	0.7
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	190	190	190
Stack Gas Exit Velocity (ft/sec)	63.3	59.2	55.4

Notes:

(1) Emission estimates based on manufacturer's data; see Appendix A

(2) For CTs the heat-input rate is based on the higher heating value (HHV) of the fuel (1,030 Btu/SCF, 23,345 Btu/lb).

(3) Not corrected to ISO conditions.

VOCs = Volatile Organic Compounds

Neg. = Negligible

TABLE 2-2

COMBUSTION TURBINE UNIT (170 MW)

ESTIMATED [(1)] PERFORMANCE ON FUEL OIL

CONDITIONS			
Ambient Temperature (°F)	20	59	105
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	100	100	100
Maximum Heat Input Rate (MMBtu/hr)(2)	2,100	1,932	1,707
EMISSIONS (lb/hr)			
Carbon Monoxide (30 ppmvd)	112	106	91
Nitrogen Oxides (12 ppmvd at 15% O_2)	92.3	87.5	77.3
Sulfur Dioxide	105.6	97.1	85.8
Particulate Matter (PM_{10})	64.8	59.6	52.5
Opacity (%)	20	20	20
Volatile Organic Compounds (10 ppmvw)	22	21	19
Lead (4)	0.022	0.021	0.018
Sulfuric Acid Mist	16	15	13
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	270	270	270
Stack Gas Exit Velocity (ft/sec)	69.4	67.0	60

Notes: (1) Emission estimates based on manufacturer's data; see Appendix A.
(2) For CTs the heat input rate is based on the higher heating value (HHV) of the fuel (19,892 Btu/lb).

TABLE 2-3

MAXIMUM POTENTIAL ANNUAL EMISSIONS (530 MW) AND PSD SIGNIFICANCE VALUES

Pollutant	Emissions (TPY)[a]	PSD Significant Emission Rate (TPY)	PSD Review Required (Yes/No)
Carbon Monoxide	744	100	Yes
Nitrogen Oxides	267	40	Yes
Sulfur Dioxide	137	40	Yes
Particulate Matter (PM_{10})	121	15	Yes
Total Suspended Particulates	121	25	Yes
Volatile Organic Compounds	57	40	Yes
Lead	0.02	0.6	No
Sulfuric Acid Mist	21	7	Yes
Individual HAPs	2.0	10[b]	NA
Total HAPs	7.3	25[b]	NA

[a] TPY = Tons per year for the proposed Power Block 3 project.

Basis: Refer to Table A-25 in Appendix A.

[b] Criteria for review under 112 g regulations for determination of MACT.

TABLE 2-4
TYPICAL NATURAL GAS ANALYSIS

ANALYSIS	MOLE (%)
Carbon Dioxide	0.576
Ethane	2.18
Hexanes Plus	0.0077
Iso-Butane	0.064
Methane	96.55
Nitrogen	0.213
Normal-Butane	0.063
Pentanes Plus	0.018
Propane	0.299
Total:	100.000
Specific Gravity (air at 1)	0.5782
Quality Information	**Parameters**
Heating Value (HHV)	1030 Btu/cf
Total Sulfur (Maximum)	1 grain/100 SCF

Source: Florida Gas Transmission

TABLE 2-5

TYPICAL NO. 2 FUEL OIL ANALYSIS

NO. 2 DISTILLATE OIL	PERCENT (BY WEIGHT)
Carbon Residue	<0.01
Nitrogen	0.015[a]
Sulfur	0.05[b]
Ash	0.05 [a]

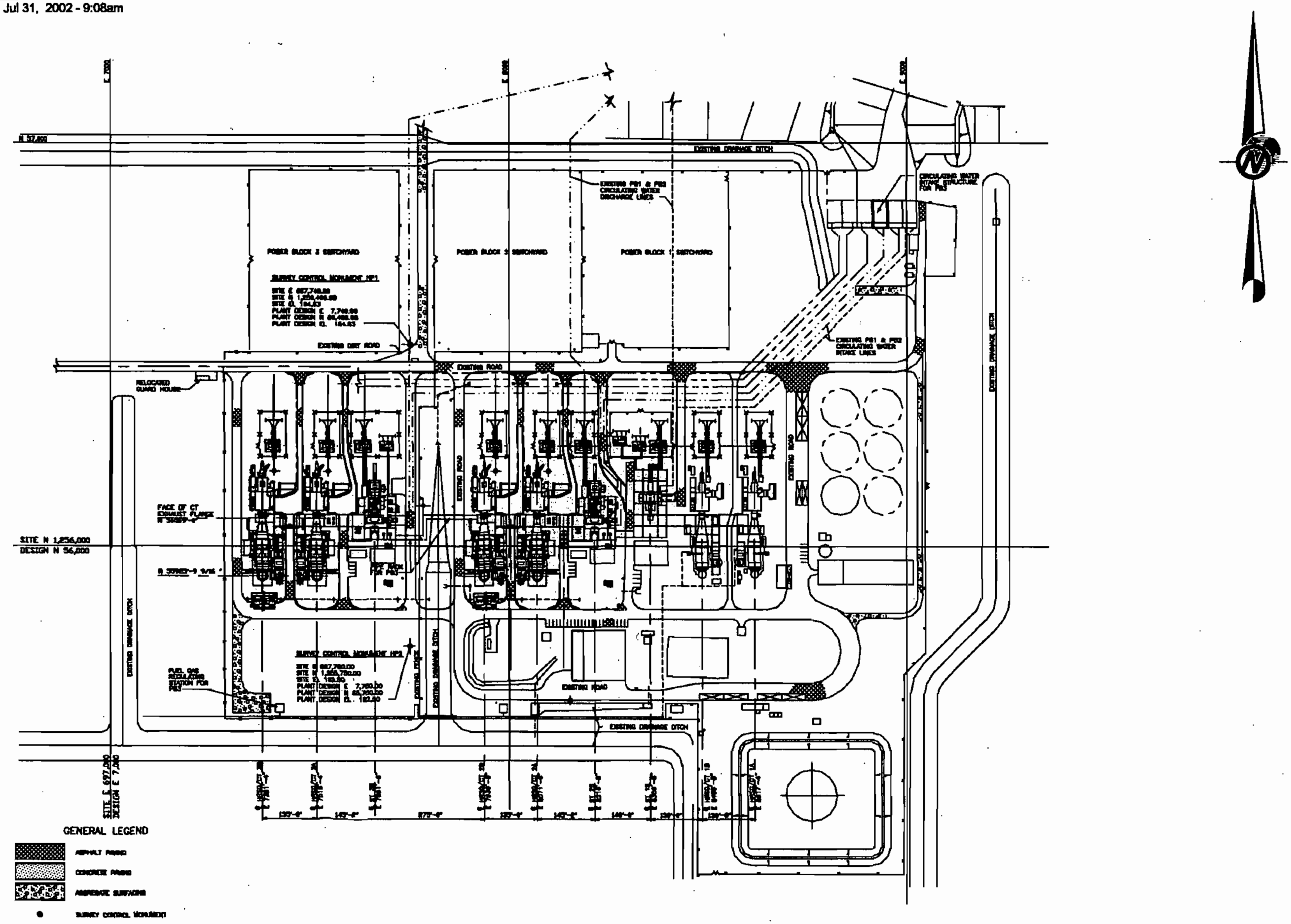
Lower Heating Value:	17,290 Btu/lb
Higher Heating Value:	19,892 Btu/lb

[a] Emission guarantees based on these values.

[b] The sulfur content is the maximum, as required by permit.

Source FP, 1999

Drawing file: 0237539A041 fig 2-1.dwg Jul 31, 2002 - 9:08am

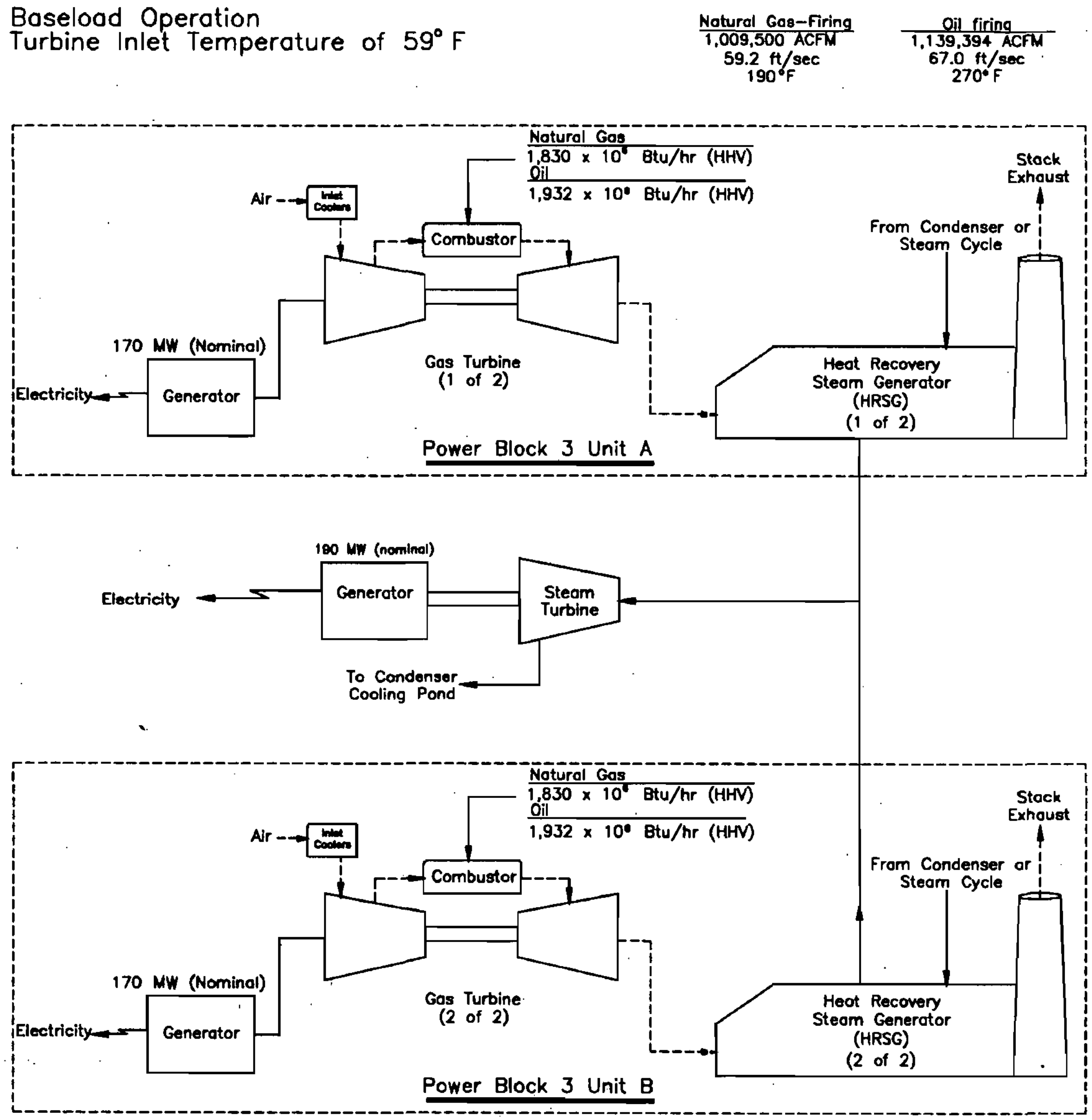


Florida Power
A Progress Energy Company

Hines Energy Complex

FIGURE 2-1
SITE ARRANGEMENT MAP

Drawing file: 0237539A042 fig 2-2.dwg Jul 31, 2002 - 10:49am



Florida Power
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Hines Energy Complex

FIGURE 2-2
PROCESS FLOW DIAGRAM

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to Power Block 3. These regulations must be satisfied before the proposed facility can be constructed and begin operation.

3.1 NATIONAL AND FLORIDA AMBIENT AIR QUALITY STANDARDS (NAAQS/FAAQS)

The applicable federal and state ambient air quality standards are presented in Table 3-1 (PSD increments are also presented in Table 3-1, but discussed in Section 3.2.2). The primary National Ambient Air Quality Standards and Florida Ambient Air Quality Standards (NAAQS/FAAQS) were promulgated to protect the public health, and the secondary NAAQS/FAAQS were promulgated to protect the public health and welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Polk County is an attainment area for all criteria pollutants, meaning that existing ambient concentrations meet the allowable standards.

3.2 PSD REVIEW REQUIREMENTS

3.2.1 General Requirements

Under the federal and FDEP Prevention of Significant Deterioration (PSD) permit review requirements, all major new or modified existing sources of air pollutants located in attainment areas and regulated under the Clean Air Act (CAA) must be reviewed and approved. A "major stationary source" is defined as any one of 28 specified source categories which has the potential to emit 100 tons per year (TPY) or more, or any other stationary source which has the potential to emit 250 TPY or more of any air pollutant regulated under the CAA. Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr of heat input comprise one of the 28 specified source categories. As Power Block 3 constitutes a modification to an existing major source, the proposed project "potential to emit" is compared to the PSD significant emission rates (TPY). The term "potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. As presented earlier in Table 2-3, the potential emissions from the proposed project will exceed the significance rates for all criteria pollutants; therefore, the project is considered a modification to an existing major stationary source and is subject to PSD review.

PSD review is used to ensure that significant air quality deterioration will not result from the new or modified source located in an attainment area. The PSD regulations are contained in rule 62-212.400 F.A.C. Major sources and modifications are required to undergo the following analyses under PSD for each air pollutant emitted where potential emissions exceed the significant emission rates:

- A control technology analysis;
- An air quality impacts analysis; and
- An additional impacts analysis.

In addition to these analyses, a new source must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations (EPA, 1985a), New Source Performance Standards (NSPS), and any applicable state emission standard as discussed in Section 3.3.

3.2.2 PSD Increments/Classifications

In promulgating the 1977 Clean Air Act (CAA) Amendments, Public Law 95-95, Congress specified that certain increases above an air quality "baseline concentration" level for SO_2 and TSP concentrations would constitute "significant deterioration." The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have a significant impact. Three classifications were designated based on criteria established in the CAA Amendments.

Initially, Congress designated PSD areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would allow greater deterioration than Class II areas, were designated. EPA subsequently incorporated the requirements for classifications and area designation into the PSD regulations.

On October 17, 1988, the EPA promulgated regulations to prevent significant deterioration due to NO_X emissions and established PSD increments for NO_2 concentrations. The allowable PSD increments for SO_2, TSP, and NO_2 are presented in Table 3-1. The FDEP has adopted the EPA PSD classification scheme and the allowable PSD increments for SO_2, PM_{10}, and NO_2.

The term "baseline concentration" is derived from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and contributions from certain additional baseline sources. The PSD regulations (40 CFR 51.166) define baseline concentration as the ambient concentration level which exists in the baseline area at the time of the applicable baseline date. Emission increases after the baseline date consume PSD increments. A baseline concentration is determined for each pollutant for which PSD increments are promulgated and a baseline date is established. The baseline concentration includes:

The actual emissions representative of sources in existence on the applicable baseline date; and

The allowable emissions of major stationary sources which commenced construction before January 6, 1975, for SO_2 and PM_{10} concentrations, or before February 8, 1988, for NO_2 concentrations, but which were not in operation by the applicable baseline date.

The air quality analysis results, which demonstrate project compliance with these requirements, are presented in Section 7.0.

3.2.3 Control Technology

The control technology review requirements of the PSD regulations require that all applicable federal and state emission-limiting standards be met and that Best Available Control Technology (BACT) be applied to control emissions from the source. The BACT requirements apply to all applicable regulated and unregulated air pollutants for which the increase in emissions from the source or modification exceeds significant emission rate.

BACT is defined in rule 62-210.200 F.A.C. as:

> An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case

> basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

(a) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emission unit 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.

(b) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

The requirements for BACT were incorporated within the PSD framework in the 1977 CAA Amendments. The primary purpose of BACT is to minimize consumption of PSD increments and thereby increase the potential for future economic growth without significantly degrading air quality. Guidelines for the evaluation of BACT can be found in the draft "New Source Review Workshop Manual" (EPA, 1990b) and the draft "Top-Down BACT Guidance Document" (EPA, 1990c). These guidelines were issued 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. The "top-down" approach to BACT has been followed in this application. BACT is determined on a case-by-case basis, and BACT for a source in one area may not be the same for an identical source located in another area. BACT analyses for the same types of emissions units 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.

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, at a minimum, demonstrate compliance with 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 determination of BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts. Section 4.0 presents the BACT discussion and recommendations for this project.

3.2.4 Ambient Air Quality Monitoring Requirements

In accordance with the requirements of Rule 62-212.400(5)(f) F.A.C., any application for a PSD permit must contain an analysis of ambient air quality monitoring data in the area affected by the proposed major stationary source or major modification.

In accordance with Rule 62-212.400(5)(f)(2), ambient air monitoring for a period of up to one year may be required to satisfy the PSD monitoring requirements. A minimum of four months of data would be required. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered.

However, the FDEP PSD regulations include an exemption, which excludes or limits the pollutants for which an ambient air quality analysis must be conducted (Rule 62-212.400(3)(e)). This exemption states that a proposed major stationary source or major modification is exempt from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the source or modification would cause, in any area, air quality impacts less than the *de minimis* air quality impact levels presented in Table 3-2.

Ambient air quality monitoring data is discussed in Section 5.0 of this application.

3.2.5 Source Impact Analysis

A source impact analysis of air quality must be performed for a proposed major source subject to PSD for each air pollutant for which the increase in emissions exceeds the significant emission rate. The PSD regulations specifically require the use of atmospheric dispersion models in performing air quality impact analysis, estimating baseline and future air quality levels, and determining compliance with NAAQS/FAAQS and allowable PSD increments. Reference EPA models must normally be used in performing the impact analysis. Use of non-reference EPA models requires EPA's consultation and prior approval. Guidance for the regulatory application of dispersion models is presented in the U.S. EPA "Guideline on Air Quality Models (Revised)" (EPA, 1997). The modeling methodology utilized for the source impact analysis is described in detail in Section 6.0 of this application.

3.2.6 Additional Impacts Analysis

In addition to air quality impact analyses, the 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. These analyses are to be conducted primarily for PSD Class I areas. Impacts on air quality due to general commercial, residential, industrial, and other growth related activities associated with the source must also be addressed. These analyses are required for each pollutant emitted in significant quantities. Section 8.0 of this application contains the additional impact analyses.

3.3 OTHER REQUIREMENTS

In addition to the requirements of the PSD program, any new or modified source of air pollution must be reviewed with respect to the GEP stack height regulations (EPA, 1985a), the federal NSPS requirements, and any state-specific emission standards.

3.3.1 Good Engineering Practice (GEP) Stack Height

The 1977 CAA Amendments require under Section 123 that the degree of emission limitation required for control of any air 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).

The EPA's final stack height regulations define GEP stack height in part as the greater of:

(1) 65 meters, measured from the ground-level elevation at the base of the stack; or

(2) $H_g = H + 1.5 L$

where:

H_g = GEP stack height, measured from the ground-level elevation at the base of the stack;

H = Height of nearby structure(s) measured from the ground-level elevation at the base of the stack; and

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

The term "nearby" is defined by the GEP stack height regulations 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 credit used in modeling for determining compliance with NAAQS/FAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. In this case, the proposed stacks for each unit are 125.0 feet (38.1 meters) above ground level. This height does not exceed the *de minimus* GEP stack height of 65m. See Section 6.7 of this application for a discussion of building downwash considerations for this project.

3.3.2 New Source Performance Standards (NSPS)

The CAA required the U.S. EPA to adopt standards of performance for new or modified stationary sources of air pollution. To date, the U.S. EPA has adopted regulations for approximately 80 stationary source categories. These regulations are contained in 40 CFR Part 60. A review of the regulations reveals that the Power Block 3 CC units are subject to a specific NSPS. Any source subject to a specific NSPS is also subject to the general provisions of 40 CFR 60 Subpart A.

3.3.2.1 General Provisions

The general provisions of the NSPS regulations are found in 40 CFR 60, Subpart A. The general provisions specify the notification and record keeping requirements (40 CFR 60.7), compliance with standards and maintenance requirements (40 CFR 60.11), and the monitoring requirements (40 CFR 60.13) for each affected source.

3.3.2.2 Combined Cycle Units

NSPS for combined cycle units are covered in 40 CFR 60 and potentially include: Subpart Da-Standards of Performance for Electric Utility Steam Generating Units, for which construction is commenced after September 18, 1978; in 40 CFR 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; and in 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines. Because the steam generators associated with Power Block 3 (i.e., HRSGs) will utilize only the waste heat from the combustion turbines, only the requirements of Subpart GG and Subpart A will apply.

Subpart GG regulates the CC units as electric utility stationary gas turbines and establishes emission limitations on both NO_x and SO_2. The NO_x emission limitation is set by the following equation:

$$STD = 0.0075 \frac{(14.4)}{Y} + F \qquad 1$$

where:

STD =allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_X emission allowance for fuel-bound nitrogen as defined below:

Fuel-bound nitrogen (percent by weight)	F (NO_X percent by volume)
N<0.015	0
0.015<N<0.1	0.04(N)
0.1<N<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).

This results in an emission limitation of 113.5 parts per million on a dry volume basis (ppmvd) at 15 percent oxygen for the proposed units when fired on natural gas and 112.7 ppmvd at 15 percent oxygen when fired on fuel oil. (These values do not include the allowance for fuel-bound nitrogen). The SO_2 emission limitations are set at 150 ppmvd corrected to 15 percent oxygen in the exhaust stream or a fuel sulfur content less than or equal to 0.8 percent by weight.

40 CFR 60 Subparts Da, Db, and Dc are not applicable to the CC units since the HRSGs will not be fired with any type of auxiliary fuel.

3.3.2.3 Excess Emissions

The EPA has adopted general and specific recordkeeping and reporting requirements relating to excess emissions in 40 CFR 60.7(b) and 40 CFR 60.334(c). The EPA requirements specify maintaining records and submittal of a quarterly report (calendar year) on excess emissions associated with start-ups, shutdowns, malfunctions, inoperative continuous monitoring systems, low water-to-fuel ratio, and fuel sulfur content greater than 0.8% by weight. The reporting requirement includes submittal of the semi-annual report even when no excess emissions occur. EPA has not adopted any specific time limits related to excess emissions from a CC unit, or from combustion turbine units regulated under 40 CFR Part 60, Subpart GG.

3.3.3 State-Specific and General Emission Standards

In addition to federal requirements, FDEP has adopted specific and general emission limiting and performance standards. These standards may be found in rule 62-296, F.A.C. The requirements of these standards must be met along with any federal PSD or NSPS limitation or requirement.

3.3.3.1 General Emission Standards

The FDEP has adopted general particulate matter emission limits as well as general pollutant emission limits (rule 62-296.320, F.A.C.). These limits apply when no specific emission standard is applicable.

3.4 SOURCE APPLICABILITY

3.4.1 Pollutant Applicability

The PSD regulations apply to the proposed generation project due to the attainment status for the Polk County Site. Polk County and the surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. The Polk County Site is located approximately 118 km southeast of the Chassahowitzka National Wilderness Area (NWA), the nearest PSD Class I area. The Chassahowitzka NWA is that portion of the Chassahowitzka National Wildlife Refuge that has been officially designated as wilderness.

Pollutant applicability for the proposed facilities is addressed in Sections 2.0 and 4.0 and briefly summarized here. The proposed Power Block 3 project is considered to be a modification to an existing major source under the PSD regulations. PSD review is required for any regulated pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 2-3. As shown, the potential emissions for the proposed facilities will exceed the PSD significant emission rates for the following regulated pollutants: CO, NO_X, SO_2, PM_{10}, VOC, and sulfuric acid mist. The proposed project is subject to PSD review for these pollutants.

3.4.2 Ambient Air Quality Monitoring

Based upon the net increase in emissions from the proposed facility presented in Table 2-3, a PSD preconstruction ambient air monitoring analysis is required, as part of the air quality impact analysis for CO, NO_2, SO_2, PM_{10}, O_3 (based on VOC emissions), and sulfuric acid mist. However, if the net increase in a source's impact of a pollutant is less than the *de minimis* air quality impact level, as shown in Table 3-2, then preconstruction ambient air quality monitoring is not required for that pollutant. In addition, if an acceptable ambient air monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Dispersion modeling was performed to determine those pollutants that could be exempted from the monitoring requirement. As described in Sections 6.0 and 7.0, the increases in air quality impacts are predicted to fall below the *de minimis* impact levels presented in Table 3-2; therefore, pre-construction monitoring is not required. The results for these pollutants are presented in Section 5.0.

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

Pollutant	Averaging Time	AAQS ($\mu g/m^3$)			PSD Increments ($\mu g/m^3$)		Significant Impact Levels ($\mu g/m^3$)
		Primary Standard	Secondary Standard	Florida	Class I	Class II	
Particulate Matter (PM10)	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	1-Hour Maximum	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 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/m^3)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour

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

NAAQS = National ambient air quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
g/m^3 = Micrograms per cubic meter.

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

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

Sources: 40 CFR 52.21.
Rule 62-212.400

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_x, SO_2, CO, PM/PM_{10}, VOC, and sulfuric acid mist (see Section 2.0). The maximum potential annual emissions of these pollutants from the proposed "F" Class CTs are summarized in Table 2-3.

This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a top-down approach. A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12)]. The analysis must be, by definition, specific to the project (i.e., case by case).

4.2 NEW SOURCE PERFORMANC STANDARDS

The applicable NSPS for CTs are codified in 40 CFR 60, Subpart GG and summarized in Appendix B. The applicable NSPS emission limit for NO_x is 75 parts per million by volume dry (ppmvd) corrected for heat rate and 15-percent O_2. For the CTs being considered for the Project, the NSPS emission limit for NO_x, with the NSPS heat rate correction, is over 100 parts per million (ppm) firing natural gas and distillate oil (corrected to 15-percent O_2 at a fuel-bound nitrogen content of 0.015 percent). The proposed NO_x emission limits for the Project will be 29 times lower than the NSPS when firing natural gas and 8 times lower than the NSPS when firing distillate oil.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 Overview Of Proposed BACT

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

1. The Project will use state-of-the-art DLN combustion technology and SCR to achieve gas turbine exhaust NO_x levels of no greater than 3.5 ppmvd corrected to 15-percent O_2, 24-hour block average (midnight-to-midnight) when firing natural gas and 12 ppmvd corrected to 15-percent O_2, 24-hour block average (midnight-to-midnight) when firing oil.
2. CO emissions when firing natural gas will be limited to 16 ppmvd corrected to 15-percent O_2, and 30 ppmvd corrected to 15-percent O_2, when firing distillate oil.
3. VOC emissions when firing natural gas will be limited to 2.0 ppmvd corrected to 15-percent O_2 and when firing distillate oil VOC will be limited to 10 ppmvd corrected to 15-percent O_2.
4. Emission rates of PM_{10}, SO_2, and SAM will be limited using natural gas.

A summary of the emission rates proposed as BACT is presented in Table 4-1.

4.3.2 NITROGEN OXIDES

4.3.2.1 Introduction

The BACT analysis was performed based on those available and feasible control technologies that can provide the maximum degree of emission reduction for NO_x emissions. An evaluation of the available and feasible control technologies determined that combustion along with SCR could provide the maximum degree of emission reduction. $SCONO_x$™ is commercially available but has not been demonstrated on "F" Class combustion turbines. Other available technologies such as NO_xOut, Thermal DeNO_x, SNCR, and XONON™ Combustion System were evaluated and determined to be technically infeasible or not commercially demonstrated for the Project. Appendix B presents a discussion of these NO_x control technologies and their feasibility for the Project.

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

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

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

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

Although $SCONO_x$™ is technically feasible, it has not been demonstrated on a "F" Class combustion turbine. Performance data on future applications on "F" Class turbines considering $SCONO_x$™ will only likely be available after 2005, well after the facility is scheduled for construction. The $SCONO_x$™ system has only been operated on a 32-MW facility in California since 1996 and a 5 MW unit in Massachusetts since 1999. The scale up of this complicated technology should not be underestimated. The $SCONO_x$™ technology installed on an "F" Class turbine would involve about a dozen or more different chambers of catalyst for absorption and regeneration. Every 15 to 30 minutes, dampers would be operated to isolate a particular catalyst chamber for regeneration. Each regeneration cycle must isolate the chamber so that oxygen is not introduced and regeneration gas (hydrogen) is introduced. Seal leaks could be significant as applied to the large volume flows associated with a "F" Class turbine. Although the amount of sulfur in natural gas is very low, the $SCONO_x$™ catalyst is poisoned with sulfur compounds requiring the installation of the $SCOSO_x$™ to further remove sulfur compounds as part of the overall system. While the distillate oil proposed for the Project will contain 0.05-percent sulfur or less, the amount will be about 20 times higher than that normally contained in natural gas. The ability of $SCOSO_x$™ to further remove sulfur compounds as part of the overall $SCONO_x$™ system has not been demonstrated when firing distillate oil.

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

The proposed CTs will be fired primarily with natural gas with distillate oil as a backup fuel. Table 4-2 presents a summary of emissions for the Project. The BACT evaluation was based on DLN combustors in combination with SCR and $SCONO_x$™.

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

4.3.2.2 Impacts Analysis

Economic--The total estimated capital costs, annualized costs, and incremental cost effectiveness of adding SCR and $SCONO_x$™ to the DLN combustors on a CT/HRSG are as follows:

	SCR	$SCONO_x$™	% Difference
Capital Cost	$3,470,485.0	$26,572,482.0	765
Annualized Cost	$1,809,118.0	$5,673,648.0	314
Cost Effectiveness from DLN Combustors per ton NO_x removed. (25 ppmvd to 3.5 ppmvd)	$2,741.0	$8,597.0	314

Appendix B contains the detailed cost estimates for the capital and annualized costs. The capital and annualized costs for SCR and $SCONO_x$™ are based on a budgetary cost estimates provided by Englehard and ABB Alstom Environmental Systems, respectively. As shown above, the $SCONO_x$™ capital cost and cost effectiveness are 765% and 314% greater than that of SCR with uncertainty in its demonstrated feasibility. It should be noted that the annualized costs for $SCONO_x$™ did not include provisions for required mechanical maintenance activities. $SCONO_x$™ control technology clearly has an economic disadvantage compared to SCR, while achieving the same NO_x control.

Environmental--The maximum predicted annual average NO_x impact of the Project compared to the PSD Class II increment and AAQS is as follows:

Maximum Annual Project NO_x Impact	Annual NO_x PSD Class II Increment	Annual NO_x AAQS	Percent of the AAQS
(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)
0.094	25	100	0.094

The addition of SCR will reduce NO_x emissions by about 660 TPY per CT/HRSG (about 82-percent reduction) beyond those achieved through the use of DLN combustors.

The use of DLN combustor technology is "pollution prevention". The use of SCR has associated primary and secondary environmental impacts. Emissions of ammonia and ammonium salts (such as ammonium sulfate and bisulfate) will occur. Ammonia emissions with the use of SCR are a result of unreacted ammonia that may be emitted. Vendors typically provide ammonia slip guarantees of 9 ppmvd corrected to 15-percent O_2. Maximum ammonia emissions are 113 TPY at the guarantee ammonia slip level. However, this level of ammonia slip occurs only as the catalyst ages. Initial ammonia slip levels are less than 5 ppmvd. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10} and up to 9.9 TPY could be emitted.

The electrical energy required to run the SCR system and the backpressure on the turbine will reduce the available power from the Project. The backpressure is a result of the catalyst modules located in the exhaust gas stream in the HRSG. With use of DLN combustors at an emission level of 25 ppmvd (corrected to 15-percent O_2), the backpressure to reduce NO_x to 3.5 ppmvd (corrected to 15-percent O_2), based on vendor data, is about 2.7 inches of water gauge. This backpressure reduces the power generated by the combustion turbine. This lost power, which would otherwise be available to the electrical system, will have to be replaced by other less efficient units. The replacement power will cause secondary air pollutant emissions that would not have occurred without SCR. The net reduction in emissions with SCR (i.e., reduction in NO_x minus ammonia and secondary emissions), when all criteria pollutants are considered, will be about 520 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted.

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

While ammonia is not used or emitted from a $SCONO_x$™ system, there are substantial natural gas, steam requirements, and increased turbine backpressure for the $SCONO_x$™ system that would directly result in environmental impacts. $SCONO_x$™ requires about 18,000 lb/hr of steam and 80 lb/hr of natural gas for operation. In addition, the backpressure of the $SCONO_x$™ system is 200 percent over that of the SCR. This increased energy use would create additional criteria pollutants of about 41 tons per year per unit and about 23,000 tons per year per unit of additional carbon dioxide emissions compared to the Project using SCR (i.e., about 3,700 tons of carbon dioxide per year per unit).

Energy--Energy penalties occur with SCR and $SCONO_x$™ systems. The output of the CT will be reduced over that of advanced low-NO_x combustors due to the backpressure on the CT. The energy penalties of SCR and $SCONO_x$™ with a low base emission level (i.e., 25 ppmvd corrected to 15-percent O_2) and 82 percent NO_x reduction are as follows:

	Units	SCR	$SCONO_x$™	% Difference
Backpressure	inches of water	2.7	5.0	185
CT Output Reduction	%	0.32	0.6	188
Equivalent Lost Energy	kWh/yr	5,155,560	9,552,254	185
Energy Requirement	kWh/yr	700,800	26,045,082	3,716
Total Lost Energy	kWh/yr	5,856,360	35,597,336	608
Equivalent Residential Customers/year	Customers	488	2,966	608
Equivalent Heat Loss	MMBtu/yr	58,970	358,441	608
Equivalent Natural Gas	mmcf/yr	59	358	608

As shown above, $SCONO_x$™, in contrast to SCR, is very energy intensive. The $SCONO_x$™ system has about 2 times more backpressure on the turbine and requires steam and natural gas for the regeneration process. The natural gas needed to generate the steam for the $SCONO_x$™ system is equivalent to 26 MMBtu/hr/unit or 230,000 MMBtu per year per unit. When all the energy requirements for $SCONO_x$™ are considered, it is about 2.24 percent of the combustion turbine heat input. In contrast, SCR results in an additional 0.37 percent of the combustion turbine heat input.

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

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

The second unique attribute of the advanced machine is the use of DLN combustors that will reduce NO_x emissions to 25 ppmvd when firing natural gas. Thermal NO_x formation is inhibited by using staged combustion techniques where the natural gas and combustion air is premixed prior to ignition. This level of control will result in NO_x emissions of about 0.04 lb/10^6 Btu for gas firing, which are less than half of the emissions generated from conventional fossil fuel-fired steam generators.

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

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

NO_x Emission Rate of 2.5 ppmvd Corrected to 15-percent O_2-Appendix B contains cost evaluations for NO_x emission rates of 3.5 and 2.5 ppmvd corrected to 15-percent O_2 when firing natural gas. The NO_x emission rate when firing distillate oil was kept at 12 ppmvd corrected to 15-percent O_2. The costs for SCR were adjusted based on vendor estimates. For $SCONO_X$, the capital cost was kept the same and only the catalyst changeout costs were increased.

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

	SCR @ 3.5 ppmvd	SCR @ 2.5 ppmvd
Total Annualized Costs	$1,809,118	$1,899,167
Cost Effectiveness	$2,741	$2,770
	$SCONO_X$ @ 3.5 ppmvd	$SCONO_X$ @ 2.5 ppmvd
Total Annualized Costs	$5,673,648	$5,751,900
Cost Effectiveness	$8,897	$8,390
Note: Total tons removed are 660 tons/year at 3.5 ppmvd and 686 tons/year at 2.5 ppmvd.		

It should be emphasized that $SCONO_X$ is not considered a demonstrated technology for "F" Class combustion turbines and has not been used or proposed when firing distillate oil. Moreover, the operational experience is non-existent on "F" Class turbines. Indeed, the cost effectiveness did not consider any additional operational cost of this technology as a result of the extensive mechanical equipment required. Moreover, $SCONO_X$ has considerable collateral environmental and energy impacts as noted in the application.

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

Incremental Cost effectiveness (3.5 to 2.5 ppmvd)	
$1,899,167	Annualized cost for SCR at 2.5 ppmvd
$1,809,118	Annualized cost for SCR at 3.5 ppmvd
$90,049	Difference
107	tpy emissions at 2.5 ppmvd
133	tpy emissions at 3.5 ppmvd
26	tpy reduced
$3,463	Incremental Cost Effectiveness

As shown in the table, the incremental cost effectiveness for an SCR system from achieving 3.5 to 2.5 ppmvd corrected to 15-percent O_2 increases to over $3,000 per incremental ton of NO_x removed.

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

There would also be collateral environmental consequences to achieve a NO_X emission rate of 2.5 ppmvd corrected to 15-percent O_2 rather than 3.5 ppmvd corrected to 15-percent O_2. This will be a direct result of increased backpressure on the turbine resulting from more catalyst volume required. Backpressure will increase by 4 percent over the proposed BACT emission rate resulting in increased energy losses and greater secondary emissions. Indeed, the lost energy will increase by 206,222 kW-hours/year/turbine or enough additional electric power to support about 17 residential customers for a year. To supply this lost energy, at least 0.3 tons/year of additional criteria pollutants as well as 131 tons/year of additional carbon dioxide would be generated.

The Project also has a significant environmental benefit of displacing power produced by older less efficient electric generating units. As proposed, the Project would be the dispatched in favor of old less efficient units with much higher emission levels. Each turbine and HRSG associated with Project will have potential emissions of 133 tons/year of NO_x at 3.5 ppmvd corrected to 15-percent O_2. The reduction of NO_x emissions to 2.5 ppmvd corrected to 15-percent O_2 would produce an incremental reduction of only 26 tons/year/CT-HRSG.

In conclusion, an emission rate of 2.5 ppmvd corrected to 15-percent O_2 should be rejected as BACT for the following reasons:

- There would be increased difficulty in demonstrating compliance with a 2.5 ppmvd emission limit.
- There is no environmental benefit in the NO_X reduction and would cause an increase of other air emissions (ammonia and carbon dioxide).

4.3.2.3 Proposed BACT and Rationale for Combined Cycle Operation

The proposed BACT for combined cycle operation is advanced DLN combustion technology and SCR. The proposed NO_x emissions level using this technology is 3.5 ppmvd corrected to 15-percent O_2 when firing natural gas and 12 ppmvd corrected to 15-percent O_2 when firing distillate fuel oil. This combination of technology can achieve the maximum amount of emission reduction available that is technically feasible and demonstrated for the Project. SCR cannot be rejected based on the economic, environmental, and energy impacts given the recent BACT decisions on other similar projects.

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

4.3.3 CARBON MONOXIDE

4.3.3.1 Introduction

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

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

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

There are two alternatives for installing an oxidation catalyst. The first would be to install a catalyst prior to the HRSG to reduce CO emissions from the turbine. The second alternative is to install an oxidation catalyst or $SCONO_X$™ within the HRSG. Table 4-2 presents emission estimates for the two alternatives evaluated.

4.3.3.2 Impact Analysis

<u>Economic</u>--The estimated capital cost for an oxidation catalyst installed in the HRSG is $1.64 million. The annualized cost of a CO oxidation catalyst is $700,340. The resulting cost effectiveness is approximately $3,773 per ton of CO removed for gas and oil firing. No costs are associated with combustion techniques, since they are inherent in the design.

$SCONO_x$™ also reduces CO emissions. The incremental cost effectiveness for CO removal for this system is over $20,000 per ton. This is based on the differential between the annualized cost of

SCONO$_x$™ ($5.7 million) and SCR ($1.6 million) and the tons of CO potentially removed in the SCONO$_x$™ system.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst. Moreover, the air quality impacts, at the proposed CT emission rate, are predicted to be much less than the PSD significant impact levels. The maximum CO impacts are less than 0.1 percent of the applicable AAQS. There would also be no secondary benefits, such as reductions in O_3 precursors and acidic deposition, to reducing CO.

In contrast, the installation of an oxidation catalyst would create additional back pressure on the turbine that will result in lost electric generation that would otherwise be available and thus replaced by older, less efficient technology. The end result is an additional 2,030 tons/year of carbon dioxide (CO_2). The ultimate end product of CO is CO_2, regardless of whether the process results from an oxidation catalyst or in the atmosphere. The lost energy caused by the back pressure from the oxidation catalyst would result in the generation of 10 times more greenhouse gases than the amount of CO converted to CO_2 in the oxidation catalyst.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 1.5 to 2 inches of water gauge would be expected. A catalyst back pressure of 2 inches would result in an energy penalty of about three million kWh/yr. The energy penalties are sufficient to supply the electrical needs of about 265 residential customers for a year. To replace this lost energy, about 3.2×10^{10} Btu/yr or about 32 million ft^3/yr of natural gas would be required. In contrast, the total energy requirements of SCONO$_x$™ is 35.8×10^{10} Btu/yr or about 358 million ft^3/yr of natural gas.

4.3.3.3 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 16 ppmvd when firing natural gas and 30 ppmvd when firing distillate oil. Catalytic oxidation is considered unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts,
2. The economic impacts are significant (i.e., the capital cost is $1.64 million, with an annualized cost of about $700,340 per year per unit), and
3. Recent projects in Florida and Region IV have been authorized with BACT emission limits of similar magnitude.

SCONO$_x$™ is rejected as BACT based on the high differential costs of the technology. Also, as described in the BACT evaluation for NO$_x$, the use of SCONO$_x$™ on a "F" Class turbine has associated technical uncertainty, as well as significant energy and environmental impacts.

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable, since it will not produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for similar advanced CTs have set limits in the 9- to 25-ppmvd range when firing natural gas and distillate oil. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

The cost effectiveness calculations are significantly understated if the actual emission performance is considered. The actual CO emissions performance of the Siemens Westinghouse 501F turbines is expected to be much less than the guaranteed rates. This is a direct result of turbine manufacturers including significant margins on emissions of CO and VOCs to assure that NO$_X$ emission guarantees can be achieved in the combustion systems.

4.3.4 PM/PM10, SO2, and Sulfuric Acid Mist

The PM/PM$_{10}$ emissions from the CTs are a result of incomplete combustion and trace elements in the fuel. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on gas-fired or distillate oil-fired CTs.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs. The grain loading associated with the maximum particulate emissions (less than 20 lb/hr when firing natural gas) is less than 0.01 grain per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed Project.

There are no technically feasible methods for controlling the emissions of SO$_2$ and sulfuric acid mist from CTs, other than the inherent quality of the fuel. The use of flue gas desulfurization (FGD) systems are not available, technically feasible, demonstrated or cost effective on CTs using natural gas. The use of natural gas and low sulfur distillate fuel oil, clean fuels, represents BACT and will limit emissions of SO$_2$.

4.3.5 Volatile Organic Compounds

VOCs will be emitted by the CTs as a result of incomplete combustion. The proposed emission rates for VOC emissions will be the use of combustion technology and the use of clean fuels so that emissions when firing natural gas will not exceed 2.0 ppmvd and 10 ppmvd when firing distillate oil. This emission level is similar to the BACT emission levels established for other similar sources.

Combustion controls and the use of clean fuels have been overwhelmingly approved as BACT for CTs. The environmental effect of further reducing emissions would not be significant.

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

The cost effectiveness calculation is presented below:

VOC Cost Effectiveness Calculations	
4.4	lb/hr gas firing at baseload
21	lb/hr oil firing
27.6	tpy
40.0%	removal
11	tpy removed
$63,501	per ton VOC removed
90.00%	removal
24.8	tpy removed
$28,223	per ton VOC removed

At 40-percent VOC removal the cost effectiveness of an oxidation catalyst is over $60,000 per ton of VOC removed. Assuming that 90 percent reductions were available at the same cost, the cost effectiveness is over $28,000 per ton of VOC removed.

Similar to the results for CO, the actual VOC emission rates have been extremely low when compared with the emission guarantees. The actual VOC emissions are expected to be in the order of 5 times lower than the guarantee emission level.

Table 4-1. Proposed BACT Emission Limitations and Compliance Methods For Each CT/HRSG Unit

Pollutant	Emission Rate (Basis[a])	Conditions[b]	Compliance Method Proposed
Particulate Matter	WP	Gas Firing;	Fuel Monitor, VE < 10%; Initial and Annual
	WP	Oil Firing	Fuel Monitor, VE < 20%; Initial and Annual> 400 hours
Sulfur Dioxide	WP	Gas Firing;	Pipeline Natural Gas
	WP	Oil Firing	Distillate Oil (0.05% maximum sulfur)
Nitrogen Oxides	3.5 ppmvd Corrected to 15% O_2	Gas Firing	EPA Method 7E Initial Test during CEM RATA; CEM 24-hour Block Average
	12.0 ppmvd Corrected to 15% O_2	Oil Firing	EPA Method 7E Initial Test during CEM RATA; CEM 24-hour Block Average
Carbon Monoxide	16 ppmvd	Gas Firing;	EPA Method 10; Initial only and Annual
	30 ppmvd	Oil Firing	EPA Method 10; Initial only and Annual
Volatile Organic Compounds	2.0 ppmvd	Gas Firing;	EPA Methods 18, 25, or 25a; Initial only
	10 ppmvd	Oil Firing	EPA Methods 18, 25, or 25a; Initial only

Note: ppmvd = parts per million, volume dry.
WP = Work practice – natural gas and ≤ 0.05%S distillate oil.

[a] Based on maximum emission rate over turbine inlet operating conditions.
[b] Operating loads from 70 to 100 percent under all turbine inlet temperatures.

Table 4-2. NO_x and CO Emission Estimates (TPY) of BACT Alternative Technologies (per Unit)

Alternative BACT Control Technologies	Pollutant Emissions (TPY)	
	NO_x	CO
Combined-Cycle Operation[a]		
DLN/Water Injection	793	216
DLN/Water Injection with SCR or OC/SCONO$_x$^{TM} (3.5 ppmvd @15% O_2)	133	30
Reduction	(660)	(186)

[a] Emission rates are based on one CT firing natural gas at 100-percent load for 7,760 hours; firing distillate oil at 100-percent load for 1000 hours. Emission data are based on an ambient temperature of 59°F at baseload emission rate.

Note:
DLN = Dry low-NO_x.
SCR = Selective catalytic reduction.
TPY = Tons per year.
OC = Oxidation Catalyst.

5.0 AMBIENT AIR QUALITY MONITORING DATA ANALYSIS

5.1 PSD PRECONSTRUCTION MONITORNING APPLICABILITY

The maximum concentrations predicted for Power Block 3 emissions are compared to the monitoring *de minimis* levels in Table 5-1. Based on the worst-case proposed source emissions data and air quality modelling results for the proposed Power Block 3, ambient air quality monitoring is not required for SO_2, PM_{10}, NO_2, or CO because the maximum predicted impacts are less than the PSD pre-construction monitoring *de minimis* values for those pollutants (FDEP Rule 62-212.400). For ozone (O_3), annual volatile organic compound (VOC) emissions from Power Block 3 are estimated to be less than 100 tons per year. As a result, preconstruction monitoring data are also not required to be submitted as part of this application. For sulfuric acid mist, which is a noncriteria pollutant, although the proposed source's emissions are greater than the significant emission rate, EPA has established no acceptable monitoring method for this pollutant.

Therefore, per FDEP Rule 62-212.400(3)(e), Power Block 3 is exempt from preconstruction monitoring for these pollutants.

TABLE 5-1
SUMMARY OF MAXIMUM MODELED POWER BLOCK 3 IMPACTS COMPARED TO THE PSD MONITORING *DE MINIMIS* VALUES

Pollutant	**Averaging Period**	**Highest Modeled Concentration (µg/m^3)**	**PSD *De Minimis* Level (µg/m^3)**	**Greater than the *De Minimis* Level?**
Sulfur Dioxide (SO_2)	24-Hour	4.1	13	NO
Particulate Matter (PM_{10})	24-Hour	2.5	10	NO
Nitrogen Dioxide (NO_2)	Annual	0.09	14	NO
Carbon Monoxide (CO)	8-Hour	26	575	NO
Volatile Organic Compounds (VOC)	Annual	57	100 TPY	NO

Source: Golder, 2002.

6.0 AIR QUALITY MODELING APPROACH

This section summarizes the air quality modeling protocol and input parameters utilized in the air impact determinations presented in Section 7.0. Included are descriptions of the models, meteorology, options selected, listings of modeling parameters for the proposed facilities and existing sources, receptor locations, and step-by-step procedures that were used to develop the necessary projected impacts.

The scope of the required modeling analysis is limited to those pollutants that were determined to be subject to PSD review in Section 2.0, Table 2-3 for which significant impact levels and ambient air quality standards have been established (CO, NO_x, SO_2, and PM).

The proposed source emissions of sulfuric acid mist and VOC are shown in Table 2-3 to be above the PSD significant emission rates. However, for sulfuric acid mist, the PSD regulations do not define significant impact levels nor are ambient air quality standards established. In addition, VOC emissions are not modeled for single point sources, such as those for the Project, since O_3 is a pollutant formed by complex photochemical processes with regional VOC and NO_x emission sources.

6.1 GENERAL MODELING APPROACH

The PSD regulations require an air quality impact assessment consisting of a proposed source significant impact area analysis, a PSD increment consumption analysis, an ambient air quality standards impact analysis, and an additional impacts analysis. These analyses are discussed in greater detail in the following sections under specific modeling methodologies. The modeling approach followed EPA and FDEP guidelines for determining compliance with applicable PSD increments and ambient air quality standards.

These results from the modeling analyses were compared to the PSD Class II and I significance levels for each pollutant in order to determine whether additional modeling was necessary. All predicted maximum concentrations were less than the PSD Class II and I significance values and *de minimis* monitoring levels.

6.2 MODEL SELECTION AND OPTIONS

6.2.1 Dispersion Model Selection

The selection of an air quality model to calculate air quality impacts for the Hines Energy Complex was based on its applicability to simulate impacts in areas surrounding the Project as well as at the PSD Class I area of the Chassahowitzka NWA, located about 118 km from the proposed source. Two air quality dispersion models were selected and used in these analyses to address air quality impacts for the proposed source. These models were:

- The Industrial Source Complex Short Term (ISCST3) dispersion model, and
- The California Puff model (CALPUFF)

The Industrial Source Complex Short-term (ISCST3, Version 02035) dispersion model (EPA, 2002) was used to evaluate the pollutant impacts due to the proposed source in nearby areas surrounding the site. This model is maintained by the EPA on its Internet website, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). 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 was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times. To estimate impacts due to emissions from the proposed source, an emission rate of 79.365 pounds per hour (lb/hr) or 10 grams per second (g/s) was initially used to produce relative concentrations as a function of the modeled emission rate (i.e., $\mu g/m^3$ per 10 g/s). These impacts are referred to as generic pollutant impacts. Maximum air quality impacts for specific pollutants were then determined by multiplying the maximum pollutant-specific emission rate in lb/hr (g/s) to the maximum predicted generic impact divided by 79.365 lb/hr (10 g/s).

At distances beyond 50 km from a source, the CALPUFF model, Version 5.5 (EPA, 2002), is recommended for use by the EPA and FDEP. The CALPUFF model is a long-range transport model applicable for estimating the air quality impacts in areas that are more than 50 km from a source. The methods and assumptions used in the CALPUFF model were based on the latest recommendations for modeling analysis as presented in Section 8.0. This model is also maintained by the EPA on the SCRAM website.

As a result, the CALPUFF model was used to perform the significant impact analysis for Power Block 3 at the Class I area of the Chassahowitzka NWA. The CALPUFF model was also used to assess the proposed source's impact on regional haze and deposition at the Class I area (see Section 8.0). In this analysis, concentrations were predicted for the operating load and ambient temperature that had the highest emissions. A more detailed description of the assumptions and methods used for the CALPUFF model is presented in Appendix C.

6.2.2 DISPERSION MODEL OPTIONS

The area surrounding the Hines Energy Complex has been determined by previous PSD permit applications to be a rural area based upon the technique for urban/rural determinations documented in the EPA "Guideline on Air Quality Models", which applies land use criteria. Based upon this determination, the rural dispersion option was used in ISCST3 model.

The Regulatory Default option was used in the ISCST3 model for this analysis. The ISCST3 model was applied without terrain adjustment data because the area in which the Polk County Site is located has very little relief (e.g., a net change in ground level elevation in the range of only 10 feet). The ISCST3 model's building downwash options were applied because the stacks for the proposed sources will be less than the stack height at which downwash effects may occur.

In the 1992 PSD application for the Hines Energy Complex, expected emissions from both Power Block 1 and Power Block 2 were included in the dispersion modeling analysis. The analysis evaluated the total impact of the two power blocks with respect to PSD increment consumption and ambient air quality impacts. The 2000 supplemental SCA application for Power Block 2 reassessed the Project impacts of Power 2 with more recent meteorological data and revised models.

Hines Power Block 3 represents a new project for the Hines Energy Complex, subject to PSD review. For this PSD application, Project impacts resulting from Power Block 3 are addressed only.

The air quality impact assessment for PM assumed that all PM emissions were PM_{10} emissions. This assumption simplified the PM modeling analysis and makes for a conservative approach to modeling PM impacts.

Descriptions of the dispersion options for the CALPUFF model are presented in Appendix C.

6.3 METEOROLOGICAL DATA

The air quality modeling analysis used hourly preprocessed National Weather Service (NWS) surface meteorological data from Tampa, Florida, and concurrent twice-daily upper air soundings from Ruskin, Florida, for the years 1991 to 1995. The meteorological data were supplied by FDEP in the preprocessed format required by the ISCST3 model. The preprocessed hourly meteorological data file for each year of record used in the analysis contains randomized wind direction, wind speed, ambient temperature, atmospheric stability using the Turner (1970) stability classification scheme, and mixing heights. The anemometer height of 6.7 meters, used in the modeling analysis, was obtained from NWS Local Climatological Data summaries for Tampa.

These meteorological data are the most complete and representative of the region around the Project Site because both the Hines Energy Complex and the weather stations are located in areas that experience similar weather conditions, such as frontal passages. In addition, these data have been approved for use by the FDEP in previous air permit applications to address air quality impacts for other proposed sources locating in Polk County and adjacent counties.

For the CALPUFF model, additional meteorological parameters are needed (e.g., precipitation, relative humidity) to predict air quality concentrations than that required for the ISCST3 model. More detailed descriptions of the assumptions and methods used for processing the meteorological data and establishing the model domain are presented in Appendix C.

6.4 EMISSIONS INVENTORY

6.4.1 Proposed Source

The proposed combined-cycle facility will have the capability of firing natural gas and low sulfur fuel oil. The fuel scenarios evaluated for the proposed source include natural gas firing at 100%, 80%, and 60% load at 20°F, 59°F, and 90°F compressor air inlets temperature; and fuel oil firing at 100%, 80%, and 65% load at 20°F, 59°F, and 105°F compressor air inlets temperatures.

The emissions inventories for the proposed source and fuel scenarios identified above are presented in Appendix A. The pollutant emission rates shown in those tables are representative of BACT as demonstrated in Section 4.0. The air quality modeling analysis for the proposed sources assumed that maximum design capacity emissions represent actual emissions for purposes of determining PSD increment consumption.

The proposed source worst-case fuel scenario was determined by modeling each temperature and load scenario for each fuel using the ISCST3 model. The maximum impacts for the proposed source were predicted in the vicinity of the Hines Energy Complex when the source is firing fuel oil at full load at 105°F for all pollutants except CO. For CO, the maximum impacts were predicted when the source is firing natural gas at 60% load at 20°F. For PSD Class I impacts, the maximum impacts for the proposed source were predicted when the source is firing fuel oil at full load at 20°F.

6.4.2 Existing Sources

The results of the proposed source significant impact area analysis (which is described in Section 7.0) indicated that the proposed facility's air quality impacts are less than the PSD significant impact levels. Therefore, no additional impact modeling to determine compliance with PSD Class II increments or ambient air quality standards impact is necessary.

6.5 RECEPTOR LOCATIONS

A description of the receptor grids used in this modeling analysis is presented below.

6.5.1 Receptor Grid for Proposed Source Significant Impact Analysis

This modeling analysis used a polar receptor grid beginning at 500 meters (m) and extending out to cover a 50-kilometer (km) radius centered over the proposed source. The polar grid consisted of 36 radials, each separated by 10-degree increments and extending outward at ring distances of 500 m, 1 km, and 1.5, 2.0, 2.5, 5.0, 10.0, 15.0, 20.0, 25.0, 30.0, 35.0, 40.0, 45.0, and 50.0 km with reference to the proposed source location.

In addition, receptors were placed at 100-meter intervals along the plant property boundary to assess the potential impact at the FP property line. An additional Cartesian receptor grid with receptors placed at 100-meter intervals was input to assess concentrations near the property line closest to the source, which is to the southeast of the facility.

In total, the receptor grid, which consisted of more than 700 receptors, is shown in Figures 6-1 and 6-2.

The modeling results indicated no significant impacts for the PSD pollutants.

6.5.2 Receptor Grid for Class I PSD Analysis

A network of 13 discrete receptors was placed at the boundary of the Chassahowitzka NWA in order to assess the potential incremental impact of the proposed source on that Class I area. The NWA receptors were obtained from the FDEP and were also used in the modeling analysis for the 1992 and 2000 PSD permit applications. The coordinates of these receptor points are listed in Table 6-1.

6.6 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with structures planned at the Hines Energy Complex, the 38.1-meter stacks for the proposed Power Block 3 will be less than the calculated value (61.0 meters) at which downwash effects would not be expected to occur. Therefore, the potential for building downwash was considered in the modeling analysis.

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

For cases where the physical stack is greater than $H_b + 0.5 L_b$, the Huber-Snyder (1976) method is used. In the case of the proposed CC units, the HRSG structures are the dominant buildings of influence. The dimensions of the HRSG structures are 24.4 meters high (H_b) and 8.0 meters wide (M_W). Since the proposed stack height of 38.1 meters is more than $H_b + 0.5 L_b$, only the Huber-Snyder downwash algorithm is used by the ISCST3 model.

A summary of the BPIP model input and output files is provided in Appendix C.

TABLE 6-1
RECEPTOR GRID USED FOR PREDICTING CONCENTRATIONS AT THE PSD CLASS I AREA OF THE CHASSAHOWITZKA NWA

Point	UTM Coordinates		Distance from Polk County Site[a]		
	East (km)	North (km)	X (km)	Y (km)	Distance (km)
1	340.3	3,165.7	-74.0	91.82	117.9
2	340.3	3,167.7	-74.0	93.82	119.5
3	340.3	3,169.8	-74.0	95.92	121.1
4	340.7	3,171.9	-73.6	98.02	122.6
5	342.0	3,174.0	-72.3	100.12	123.5
6	343.0	3,176.2	-71.3	102.32	124.7
7	343.7	3,178.3	-70.6	104.42	126.0
8	342.4	3,180.6	-71.9	106.72	128.7
9	341.1	3,183.4	-73.2	109.52	131.7
10	339.0	3,183.4	-75.3	109.52	132.9
11	336.5	3,183.4	-77.8	109.52	134.3
12	334.0	3,183.4	-80.3	109.52	135.8
13	331.5	3,183.4	-82.8	109.52	137.3

[a] Location of "zero point" for Hines Energy Complex is 414.300 km East; 3,073.880 km North

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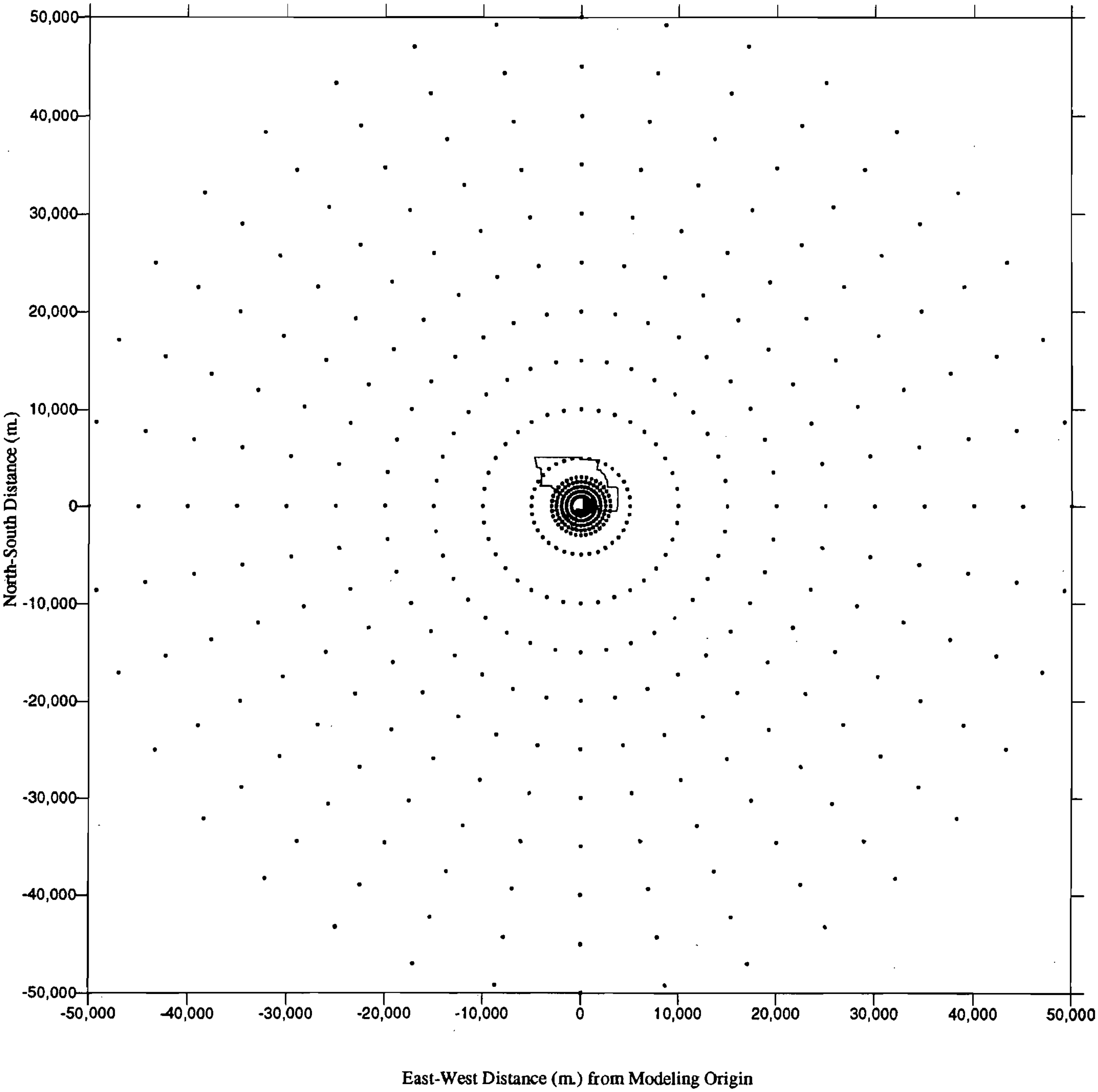
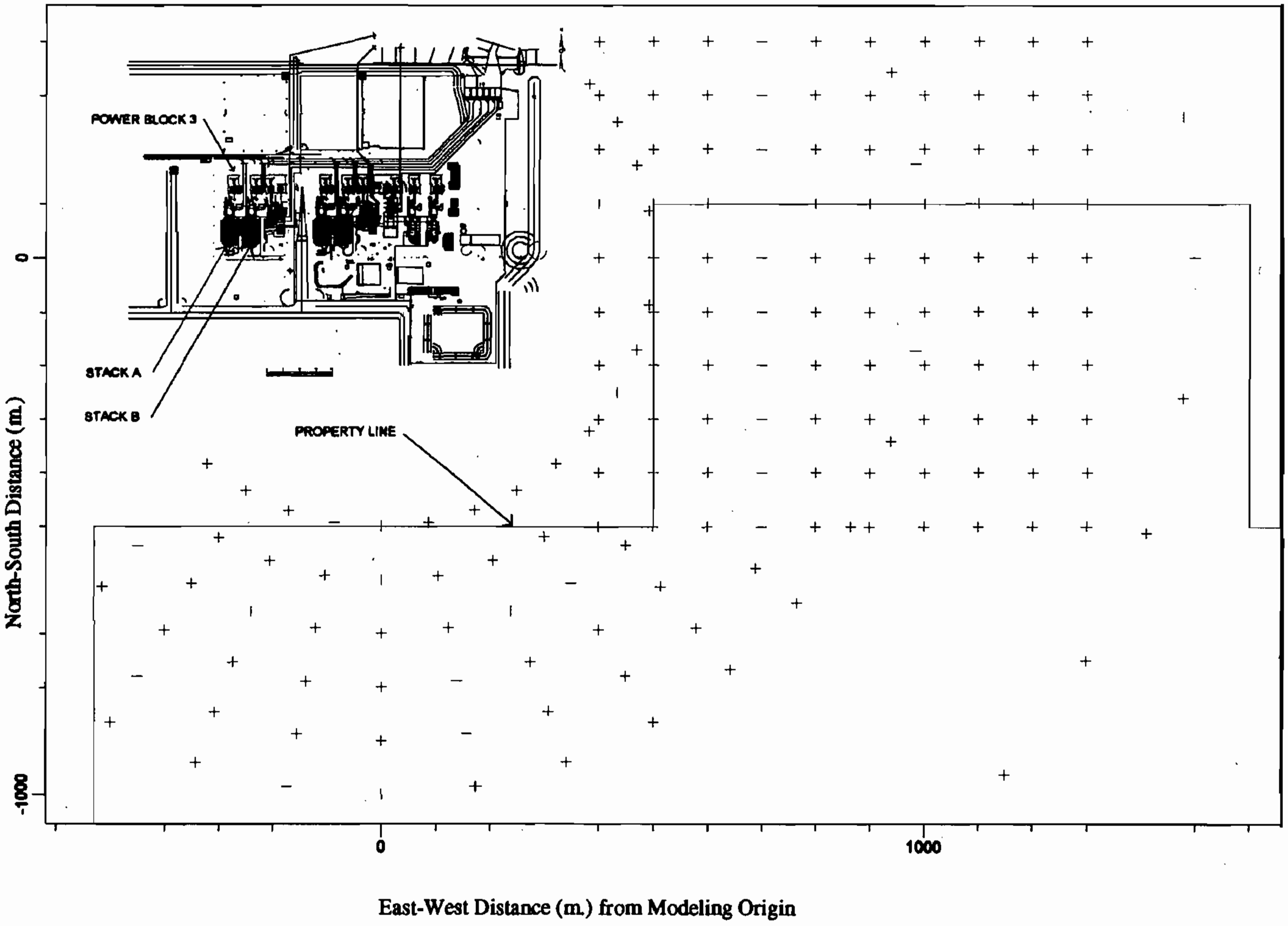


Florida Power
A Progress Energy Company

Hines Energy Complex

FIGURE 6-1
RECEPTOR GRID FOR SINGIFICANT
IMPACT ANALYSIS



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Hines Energy Complex

FIGURE 6-2
NEAR FIELD RECEPTOR GRID

7.0 AIR QUALITY IMPACT ANALYSIS RESULTS

This section summarizes the results of the modeling analyses conducted as described in Section 6.0.

7.1 POWER BLOCK 3

7.1.1 Worst-case Operation Analysis

As indicated in Section 6.4.1, the proposed Power Block 3 was evaluated for both the primary fuel, natural gas, and the back-up fuel, fuel oil, to determine the worst-case impacts. Based on the results of the ISCST3, the maximum ground-level impacts were produced for full load when firing fuel oil, except for CO emissions, which produced maximum impacts at 60% load when firing natural gas. A summary of the maximum concentrations predicted for the proposed source for the combinations of operating loads and ambient temperatures is provided in Appendix D.

Annual average concentrations were estimated by assuming that the proposed source would operate by firing fuel oil for a maximum of 1,000 hours per year and natural gas for 7,760 hours per year. The annual average concentrations were obtained by adding the maximum annual average impacts predicted for oil firing (multiplied by 1,000 hours divided by 8,760 hours) to the maximum impacts for natural gas firing (multiplied by 7,760 hours divided by 8,760 hours).

7.1.2 Significant Impact Analysis

Once the worst-case operating scenario was determined, the next step in the analysis was to determine whether the ambient air quality impact from the proposed Power Block 3 is considered significant under the PSD rules. The worst-case emissions scenario for each pollutant was modeled at the receptor locations described in Section 6.5.1.

The results of the significant impact analysis are presented in Table 7-1. As indicated in Table 7-1, there were no predicted impacts greater than the PSD significant impact levels. Thus, no further analysis is required to determine compliance with PSD increments and AAQS.

7.2 PSD INCREMENT ANALYSIS

7.2.1 Class II Area

Because the maximum predicted ambient air quality impacts for the Project are less than the PSD significance levels, no additional analysis is required to determine compliance with PSD Class II increments.

7.2.2 Class I Area

Because the proposed Project will be located approximately 118 km from the nearest boundary of the nearest Class I PSD area, the Chassahowitzka NWA, the impacts of the proposed Project were modeled at the Class I area. In its proposed New Source Review reform package, EPA has proposed PSD significance levels for Class I areas. FDEP has approved the use of these proposed values for purposes of assessing significant impacts at Class I areas in Florida (personal communication with Mr. Cleve Holladay, November 23, 1998). These values are listed in Table 7-2.

A summary of the Project's maximum predicted impact on the Class I area is presented in Table 7-2. As indicated, the maximum impacts are predicted to be below the EPA significance values for PM, PM_{10}, SO_2, and NO_2. These results are based on using the CALPUFF model. Because the maximum impact of Power Block 3 emissions are predicted to be below the EPA significance values, no further analysis is required to determine compliance with PSD Class I increments.

TABLE 7-1

SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR POWER BLOCK 3 COMPARED TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Period	Maximum Predicted Concentration [a] (µg/m³)	Polar Location [b]		Year	Significant Impact Level (µg/m³)	Distance to Significant Impact Level (km)	Predicted Impact Greater than the Significant Impact Level? (Yes/No)
			Dir. (deg.)	Dist. (m)				
Carbon Monoxide	1-Hour	80	76	412	1993	2,000	None	No
	8-Hour	25.6	117	447	1993	500	None	No
Nitrogen Dioxide	Annual	0.094	90	1500	1992	1	None	No
Sulfur Dioxide	3-Hour	17.1	130	500	1993	25	None	No
	24-Hour	4.1	117	447	1993	5	None	No
	Annual	0.037	90	1500	1992	1	None	No
Particulate Matter (PM_{10}) [c]	24-Hour	2.5	117	447	1993	5	None	No
	Annual	0.039	90	1500	1992	1	None	No

[a] Concentrations are highest values for this analysis; annual average concentrations based on firing natural gas and fuel oil for 7,760 and 1,000 hours, respectively.

[b] With respect to zero point of 414.30 km E; 3,073.88 km N.

[c] As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}.

N/A = Not applicable

Golder, 2002.

TABLE 7-2

SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR POWER BLOCK 3 COMPARED TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Period	Maximum Concentration Predicted for Power Block 2 [(a)] (µg/m^3)	PSD Class I Significant Impact Level (µg/m3)	Predicted Impact Greater than the PSD Significant Impact Level? (Yes/No)
Sulfur Dioxide (SO_2)	3-Hour	0.39	1.0	NO
	24-Hour	0.15	0.2	NO
	Annual	0.0012	0.1	NO
Particulate Matter (PM_{10})	24-Hour	0.11	0.3	NO
	Annual	0.0014	0.2	NO
Nitrogen Dioxide (NO_2)	Annual	0.0014	0.1	NO

[a] Concentrations are highest values for this analysis; annual average concentrations based on firing natural gas and fuel oil for 7,760 and 1,000 hours, respectively.

Source: Golder, 2002

8.0 ADDITIONAL IMPACTS ANALYSIS

8.1 INTRODUCTION

The PSD guidelines indicate that, in addition to demonstrating that the proposed source will neither cause nor contribute to violations of the applicable PSD increments and AAQS, an additional impacts analysis must be conducted for those pollutants subject to PSD review. As indicated in Table 2-3, those pollutants include CO, NO_X, SO_2, PM, VOC (O_3), and sulfuric acid mist. This additional impacts analysis includes an analysis of air quality impacts due to growth induced by the project, an analysis of air quality impacts on soils and vegetation, and an analysis of Project impacts on visibility.

As has been demonstrated in Section 7.0 of this application, the proposed Project will have an insignificant impact at the NWA, located from 118 to 135 km from the proposed source. In spite of this distance, FP is providing a general assessment of the impact of Power Block 3 on air quality-related values (AQRV) analysis as a part of this application.

8.2 IMPACTS DUE TO GROWTH

The growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the Project. Only impacts related to permanent growth are considered; emissions from temporary sources and mobile sources are not addressed in the growth analysis. The analysis of socioeconomic effects presented in Chapter 7.0 of the Site Certification Application serves as the basis for this growth analysis.

Up to 500 people will be employed at the Hines Energy Complex site during any one year of the construction phase for Power Block 3, and approximately 4 new permanent jobs will be filled to operate the new facility. It is anticipated that the majority of the construction workers will commute from their current residences, whereas approximately 2 of the 4 new operational employees will migrate into the Polk County area. Based on the average household size of 2.53 persons, a total of 5 persons (workers and their families) are predicted to move into the area as a result of Power Block 3. This will have an insignificant impact on the population of Polk County.

Development of industries supporting the new CC facility are expected to be negligible. Raw materials consumed by the facility (fuels, supplies, etc.) will be delivered to the site in usable form from outside of the region. Further processing, such as water treatment, will be accomplished entirely onsite.

Electricity sales, on the other hand, will be spread out over a large region as part of FP's generating capacity that will serve to meet increasing residential, commercial, and industrial demand throughout its system, which covers a large portion of the state of Florida.

In summary, there will be little residential growth associated with the FP project, and there is little potential for new industrial development nearby as a result of the new facility. Impacts resulting from the new development are expected to be small and well distributed throughout the area.

8.3 VEGETATION, SOILS, AND WILDLIFE ANALYSES

As previously discussed, the predicted maximum impacts from Power Block 3 on the NWA are less than the PSD Class I and Class II significance levels. Therefore, the project will have a negligible impact on the soils, vegetation, wildlife, and visibility of the area surrounding the plant as well as the more distant Class I area. A general discussion of air quality-related values (AQRVs) of the NWA follows.

The U.S. Department of the Interior (National Park Service) 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 (Federal Register, 1978).
>
> Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are assets that are to be preserved if the area is to achieve the purposes for which it was set aside.

In a November 1996 report entitled "Air Quality and Air Quality Related Values in Chassahowitzka National Wildlife Refuge and Wilderness Area," the US Fish and Wildlife Service discussed vegetation, soils, wildlife, visibility, and water quality as potential AQRVs in the NWA. Effects from air pollution on visibility have been evaluated in the NWA, but the other potential AQRVs have not been specifically evaluated by the Fish and Wildlife Service for Chassahowitzka. Since specific AQRVs have not been identified for the Chassahowitzka NWA, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found on the Chassahowitzka NWA.

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, 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 included: endangered species, waterfowl, marsh and waterbirds, shorebirds, reptiles and mammals.

A screening approach was used which compared the maximum predicted ambient concentration of air pollutants of concern in the Chassahowitzka NWR 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 NWR. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens and species of the hardwood swamplands and mangrove forest, no specific citations that addressed these species were found. It was recognized that effect threshold information is not available for all species found in the Chassahowitzka NWR, although studies have been performed on a few of the common species and on other similar species which can be used as models. Maximum concentrations were predicted using the CALPUFF model as described in Sections 6.0 and 7.0.

8.3.1 Vegetation

The effects of air contaminants on vegetation occur primarily from sulfur dioxide, nitrogen dioxide, ozone, and particulates. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, carbon monoxide, and pesticides have been reported in the literature. However, most of these air contaminants have not resulted in major effects (i.e., crop damage). Some air contaminants, such as ethylene, are widely distributed but, due to low concentrations, do not result in injury to plants. Others such as CO do not cause damage at concentrations normally found under ambient concentrations. There are no predicted fluoride emissions from the proposed project.

Injury to vegetation from exposure to various levels of 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, while 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.

The concentrations of the pollutants, duration of exposure and frequency of exposures influence the response of vegetation to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration, which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

Sulfur Dioxide

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When sulfur dioxide in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

Observed SO_2 effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-2 and 7-3, respectively. SO_2 gas at elevated levels has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of SO_2 range from 2.5 to 25 $\mu g/m^3$.

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour SO_2 concentrations of 790 to 1,570 $\mu g/m^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour SO_2 concentrations of 1,570 to 2,100 $\mu g/m^3$. 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 $\mu g/m^3$ SO_2 for 8 hours were not visibly damaged. This finding support the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour SO_2 concentrations of 920 $\mu g/m^3$.

Two lichen species indigenous to the park area exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 $\mu g/m^3$ for 6 hours/week for 10 weeks (Hart *et al.*, 1988).

Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 $\mu g/m^3$ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 $\mu g/m^3$ SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979).

The maximum 3-, 8-, and 24-hour average SO_2 concentrations for the Project are predicted to be 0.389, 0.284, and 0.148 μg/m^3, respectively, at the Class I area. The maximum 3-hour average SO_2 concentrations predicted for the Project at the Class I areas are 0.19 percent or less of those that caused damage to the most sensitive lichens. The modeled annual incremental increase in SO_2 adds slightly to background levels of this gas and poses only a minimal threat to area vegetation.

Nitrogen Dioxide

Nitrogen dioxide (NO_2) is another emission of concern for the proposed plant expansion. This compound can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru *et al.*, 1979).

Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 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).

The maximum 1-, 3-, and 8-hour average NO_2 concentrations due to the Project are predicted to be 0.44, 0.30, and 0.24 μg/m^3, respectively, at the Class I area. These concentrations are approximately 0.005 to 0.02 percent of the levels that could potentially injure 5 percent of the plant foliage. For a chronic exposure, the maximum annual NO_2 concentration due to the Project is predicted to be 0.004 μg/m^3 at the Class I area, which is 0.0001 to 0.0002 percent of the levels that caused minimal yield loss and chlorosis in plant tissue.

Although it has been shown that simultaneous exposure to SO_2 and NO_2 results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone and usually occurs at unnaturally high levels of each gas. Therefore, the concentrations within the park are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

Particulate Matter

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of PM that ranged from 210 to 366 μg/m^3 for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 μg/m^3 did not appear to be injurious to the tested plants.

The maximum 8-hour PM concentration due to the Project is predicted to be 0.18 μg/m^3 at the Class I area. This concentration is approximately 0.04 to 0.08 percent of the values that affected plant foliage. As a result, no significant effects to vegetative AQRVs are expected from the Project's emissions.

Carbon Monoxide

As with PM, information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of ATP, the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok *et al.* (1989) reported that exposure to $CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of 6.85 x 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 x 10^5 μg/m^3). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

The maximum 1-hour average concentration due to the Project is 0.660 μg/m^3 in the Class I area which is less than 0.001 percent of the minimum value that caused inhibition in laboratory studies. The amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season. The maximum predicted annual concentration of 0.012 μg/m^3 reflects a more realistic, yet conservative, CO level for the Class I areas. This maximum concentration is predicted to be less than 0.00001 percent of the value that caused cytochrome *c* oxidase inhibition.

Sulfuric Acid Mist

Acidic precipitation or acid rain is coupled to SO_2 emissions mainly formed during the burning of fossil fuels. This pollutant is oxidized in the atmosphere and dissolves in rain forming sulfuric acid mist which falls as acidic precipitation (Ravera, 1989). Although concentration data are not available, sulfuric acid mist has been reported to yield necrotic spotting on the upper surfaces of leaves (Middleton *et al.*, 1950).

No significant adverse effects on vegetation are expected from the project's emissions because SO_2 concentrations, which lead directly to the formation of sulfuric acid mist concentrations, are predicted to be well below levels, that have been documented as negatively affecting vegetation. During the last decade, much attention has been focused on acid rain. Acidic deposition is an ecosystem-level problem that affects vegetation because of some alterations of soil conditions such as increased leaching of essential base cations or elevated concentrations of aluminum in the soil water (Goldstein *et al.*, 1985). Although effects of acid rain in eastern North America have been well published and publicized, detrimental effects of acid rain on Florida vegetation are lacking documentation.

Summary

In summary, the phytotoxic effects on the Chassahowitzka NWA from the proposed project's emissions are expected to be minimal. It is important to note that the substances were evaluated with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

8.3.2 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.

According to the USDA Soil Surveys of Citrus and Hernando Counties, nine soil complexes are found in the Chassahowitzka NWA. These include Aripeka fine sand, Aripeka-Okeelanta-Lauderhill, Hallendale-Rock outcrop, Homosassa mucky fine sandy loam, Lacooche, Okeelanta mucks, Okeelanta-Lauderdale-Terra Ceia mucks, Rock outcrop-Homosassa-Lacoochee, and Weekiwachee-Durbin mucks (Porter, 1996). The majority of the soil complexes found in the NWA are inundated by tidal waters, contain a relatively high organic matter content, and have high buffering capacities based on their CEC, base saturation, and bulk density. The regular flooding of these soils by the Gulf of Mexico regulates the pH and any change in acidity in the soil would be buffered by this activity. Therefore, they would be relatively insensitive to atmospheric inputs. However, Terra Ceia, Okeelanta, and Lauderdale freshwater mucks are present along the eastern border of the NWA, and may be more sensitive to atmospheric sulfur deposition (Porter, 1996). Although not tidally influenced, these freshwater mucks are highly organic and therefore have a relatively high intrinsic buffering capacity.

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the Chassahowitzka NWA from the Project emissions precludes any significant impact on soils.

8.3.2.1 Lead

Lead (Pb) is found naturally occurring in all plants, although it is nonessential for growth (Chapman, 1966; Valkovic, 1975; Gough and Shacklette, 1976). Plants vary in their sensitivity to lead. Many plants tolerate high concentrations of lead, while others exhibit retarded growth at 10 ppm in solution culture (Valkovic, 1975). Orange seedlings grown on soils with lead concentrations ranging from 150-200 ppm did not exhibit adverse effects (Chapman, 1966). Gough et al. (1979) reported that a lead soil concentration of 30 to 100 g/g generally retarded the growth of plants. The negligible amount of lead emissions from Power Block 3 will not contribute to a soil concentration toxic to plants.

8.3.2.2 Mercury

Mercury (Hg) is not an essential element for plant growth. It is typically used as a seed fungicide. In general, Hg is not concentrated in plants grown on soils containing normal levels of Hg. Soil bound Hg is typically not available for plant uptake, although many plants cannot prevent the uptake of gaseous Hg through the roots (Huckabee and Jansen, 1975). Most higher vascular plants are resistant to toxicity from high Hg concentrations even though high concentrations are present in plant tissue. Concentrations of 0.5-50 ppm ($HgCl_2$) were found to inhibit the growth of cauliflower, lettuce, potato, and carrots (Bell and Rickard, 1974). Gough et al. (1979) noted apparently healthy Spanish moss plants with a mercury content of 0.5 mg/kg. The extremely small amount of mercury emissions from the proposed power block will not contribute to concentrations toxic to plants.

8.3.3 Wildlife

Compared with other threats to wildlife, such as pesticides, the toxicological relationships between air pollution and effects on wildlife are not well understood (Newman and Schreiber, 1988). The limited understanding is based primarily on reports of symptoms observed in the field and on information extrapolated from laboratory studies. Information on controlled wildlife studies is limited in the scientific literature. Most studies report symptoms of various air pollutants but do not provide toxicity levels. Those studies that do provide toxicity levels are limited to four air contaminants, SO_2, NO_2, O_3, and particulates.

Since the predicted maximum pollutant impacts are less than Class I significance levels, no adverse impacts to wildlife will occur from the proposed Power Block 3 emissions.
In addition to the impacts on wildlife from the primary pollutants, the Fish and Wildlife Service is

concerned about the effects on wildlife resulting from acid deposition (FWS, 1992). Existing acid deposition conditions in Florida were investigated during the five year Florida Acid Deposition Study (ESE, 1986 and 1987) and the two year follow-up program called the Florida Acid Deposition Monitoring Program (ESE, 1988 and 1989). The data collected in these programs indicate that Florida precipitation is only about two-thirds as acidic as precipitation across the southeastern United States and less than half as acidic as precipitation in the midwestern and northeastern United States (ESE, 1988). There is no evidence of a temporal trend in precipitation acidity since the late 1970s (ESE, 1989). The Clean Air Act Amendments of 1990 require significant reductions in SO_2 and NO_2 emissions from existing uncontrolled utility plants nationwide and some of these reductions will occur at plants in the general vicinity of the NWA. These emission reductions will undoubtedly improve on the already good estimated acid deposition conditions in the NWA.

Due to the small emission increases that will be caused by the proposed project and the resulting insignificant concentrations, increase, if any in acid deposition will be negligible.

8.4 IMPACTS UPON VISIBILITY

8.4.1 Introduction

The CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Sources of air pollution can cause visible plumes if emissions of PM_{10} and NO_x are sufficiently large. A plume will be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.

Visibility is an AQRV for the Chassahowitzka NWA. Visibility can take the form of plume blight for nearby areas or regional haze for long distances (e.g., distances beyond 50 km). Because the Chassahowitzka NWA is more than 50 km from the Project, the change in visibility is analyzed as regional haze.

Currently, there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and FLM of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report; and
- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report,* USFS, NPS, USFWS (December, 2000), referred to as the FLAG document.

The methods and assumptions recommended in these documents were used to assess visibility impairment due to the project.

8.4.2 Analysis Methodology

8.4.3 Methodology

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \text{ x } 100$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient.

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the proposed Project. The criteria to determine if the Project's impacts are potentially significant are based on a change in extinction of 5 percent or greater for any day of the year.

Processing of visibility impairment for this study was performed with the CALPUFF model (see Appendix C) and the CALPUFF post-processing program CALPOST. The analysis was conducted in accordance with the most recent guidance from the FLAG report (December 2000). The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. Daily background extinction coefficients are calculated on an hour-by-hour basis using hourly relative humidity data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document. For the Class I area evaluated, the hygroscopic and non-hygroscopic components are 0.9 and 8.5 inverse mega meter (Mm^{-1}). CALPOST then predicts the percent extinction change for each day of the year.

8.4.4 Results

The results of the regional haze analysis are presented in Table 8-5. The results indicate that the proposed Project's maximum predicted impact on visibility at the Chassahowitzka NWA is 0.63 percent for the natural gas operation and 6.2 percent for fuel oil operation. The values are below the FLM's screening criteria of 5 percent for natural gas operation and predicted to be greater than the screening level for fuel oil operation for only one day. The change in visibility due to the Project's emissions is not expected to be greater than the 5-percent criteria for several reasons. First, as discussed in Section 2.0, the Project will be limited to 1,000 hours when firing fuel oil. Since the Project will be firing oil as a backup fuel for a limited number of hours and the analysis is based on the maximum hourly emissions occurring with worst-case meteorology, the probability is low that all these conditions would occur at the same time.

Second, visibility was already impaired during the day (November 29, 1990) that the Project was predicted to be greater than the 5-percent criteria. Based on surface observations recorded for that day at Tampa International Airport, fog was reported in the area for 7 hours.

For fog to occur, the air must be saturated with moisture, resulting in high humidity. Based on the procedures in the CALPUFF model, visibility impairment for a project will be greatest when the humidity is high, such as for those hours when fog occurs. Since visibility was already impaired due to fog when the Project's emissions were predicted to produce its greatest change to visibility, it is unrealistic to expect that the Project's impacts would be noticeable during that day. The change in visibility due to the Project's emissions was predicted to be less than the 5-percent criteria.

Since the next highest visibility change due to the Project is 3.6 percent when firing oil and the Project will be firing primarily natural gas, the Project is not expected to have an adverse impact on the existing regional haze in the Chassahowitzka NWA.

8.5 SULFUR AND NITROGEN DEPOSITION

8.5.1 General Methods

As part of the AQRV analyses, total nitrogen (N) and sulfur (S) deposition rates were predicted at the Chassahowitzka NWA Class I area. The deposition analysis thresholds (DAT) are based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen or sulfur. The CALPUFF model is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition;
- Nitric acid (species HNO_3), wet and dry deposition;
- NO_x, dry deposition; and
- Ammonium sulfate (species SO_4), wet and dry deposition.

For S deposition, the species include:

- SO_2, wet and dry deposition; and
- SO_4, wet and dry deposition.

The CALPUFF model produces results in units of $\mu g/m^2/s$. The modeled deposition rates are then converted to N or S deposition in kg/ha respectively, by using a multiplier equal to the ratio of the molecular weights of the substances (IWAQM Phase II report Section 3.3).

Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition of 0.01 kg/ha/yr were provided by the U.S. Fish and Wildlife Service (January 2002). A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant. The maximum N and S depositions predicted for the Project are, therefore, compared to these DAT or significant impact levels.

8.5.2 Results

The maximum predicted N and S depositions predicted for the Project in the PSD Class I area of the Chassahowitzka NWA are summarized in Table 8-6. The maximum N and S deposition rates for the Project are predicted to be 5.18E-4 and 9.62E-4 kg/ha/yr, respectively. These maximum deposition rates are below the significant impact levels for N and S of 0.01 kg/ha/yr. As a result, the Project's emissions are not expected to have a significant adverse effect on N and S deposition at the Class I area.

Table 8-1. Maximum Pollutant Concentrations Predicted for the Project at the PSD Class I Area of the Chassahowitzka NWA

Pollutant	Averaging Time	Maximum Concentrations ($\mu g/m^3$) [a]
Natural Gas		
SO_2	Annual [c]	0.0004
	24-Hour	0.008
	8-Hour	0.016
	3-Hour	0.022
	1-Hour	0.026
PM_{10}	Annual [c]	0.0008
	24-Hour	0.014
	8-Hour	0.029
	3-Hour	0.042
	1-Hour	0.046
NO_2	Annual [c]	0.001
	24-Hour	0.031
	8-Hour	0.068
	3-Hour	0.088
	1-Hour	0.106
CO	Annual [c]	0.005
	24-Hour	0.084
	8-Hour	0.170
	3-Hour	0.231
	1-Hour	0.251
Backup Fuel Oil		
SO_2	Annual [c]	0.007
	24-Hour	0.148
	8-Hour	0.284
	3-Hour	0.389
	1-Hour	0.573
PM_{10}	Annual [c]	0.006
	24-Hour	0.106
	8-Hour	0.180
	3-Hour	0.285
	1-Hour	0.381
NO_2	Annual [c]	0.004
	24-Hour	0.109
	8-Hour	0.237
	3-Hour	0.304
	1-Hour	0.438
CO	Annual [c]	0.012
	24-Hour	0.195
	8-Hour	0.338
	3-Hour	0.495
	1-Hour	0.660

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[a] Concentrations are highest predicted using CALPUFF model and 1990 CALMET wind field for central Florida.

[b] Concentrations predicted are based the combustion turbines operating or baseload conditions at an ambient temperature of 20oF.

[c] Annual average concentrations are based on full year operation of each operating mode.

Table 8-2. SO_2 Effects Levels for Various Plant Species

Plant Species	Observed Effect Level ($\mu g/m^3$)	Exposure (Time)	Reference
Sensitive to tolerant	920 (20 percent displayed visible injury)	3 hours	McLaughlin and Lee, 1974
Lichens	200-400	6 hr/wk for 10 weeks	Hart *et al.*, 1988
Cypress, slash pine, live oak, mangrove	1,300	8 hours	Woltz and Howe, 1981
Jack pine seedlings	470-520	24 hours	Malhotra and Kahn, 1978
Black oak	1,310	Continuously for 1 week	Carlson, 1979

Table 8-3. Sensitivity Groupings of Vegetation Based on Visible Injury at Different SO_2 Exposures[a]

Sensitivity Grouping	SO_2 Concentration		Plants
	1-Hour	3-Hour	
Sensitive	1,310 - 2,620 μG/m^3 (0.5 - 1.0 ppm)	790 - 1,570 μG/m^3 (0.3 - 0.6 ppm)	Ragweeds Legumes Blackberry Southern pines Red and black oaks White ash Sumacs
Intermediate	2,620 - 5,240 μG/m^3 (1.0 - 2.0 ppm)	1,570 - 2,100 μG/m^3 (0.6 - 0.8 ppm)	Maples Locust Sweetgum Cherry Elms Tuliptree Many crop and garden species
Resistant	>5,240 μG/m^3 (>2.0 ppm)	>2,100 μG/m^3 (>0.8 ppm)	White oaks Potato Upland cotton Corn Dogwood Peach

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[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 8-4. Examples of Reported Effects of Air Pollutants at Concentrations Below National Secondary Ambient Air Quality Standards

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Sulfur Dioxide[a]	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 day/week for 10 weeks
	Decreased abundance in deer mice	13 to 157	continually for 5 months
Nitrogen Dioxide[b,c]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[a]	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	2 hours

Source: [a] Newman and Schreiber, 1988.
b Gardner and Graham, 1976.
c Trzeciak et al., 1977.

Table 8-5. Maximum 24-hour Average Visibility Impairment Predicted for the Project at the PSD Class I Area of the Chassahowitzka NWA

Operating Mode	Visibility Impairment (%)[a]			Visibility Impairment Criteria (%)
	High	2nd High	3rd High	
Natural Gas	0.63	0.48	0.40	5.0
Backup Fuel Oil	6.15[b]	3.57	3.29	5.0

[a] Concentrations are highest predicted using CALPUFF model and 1990 CALMET wind field for central Florida. Background extinctions calculated using FLAG Document (December 2000) values and hourly relative humidity data. Concentrations predicted are based the combustion turbines operating or baseload conditions at an ambient temperature of 20oF.

[b] Due to the presense of fog on the one day visibility impairment was greater than 5%, visibility was already impaired and therefore it is unrealistic to expect that the Project's ipacts would be noticeable. Therefore the change in visibility due to the Project's emissions was predicted to be less than the 5-percent criteria.

Table 8-6. Maximum Sulfur and Nitrogen Annual Deposition Predicted for the Project at the PSD Class I Area of the Chassahowitzka NWA

	Total Deposition (Wet & Dry)		Deposition Analysis Threshold
Species/Operating Mode	(µg/m2/s)[c]	(kg/ha/yr)[b]	(kg/ha/yr)
Nitrogen (N) Deposition			
Natural Gas	1.64E-06	5.18E-04	0.01
Backup Fuel Oil	1.19E-06	3.74E-04	0.01
Sulfur (S) Deposition			
Natural Gas	1.32E-06	4.15E-04	0.01
Backup Fuel Oil	3.05E-06	9.62E-04	0.01

[a] Conversion factor is used to convert µg/m^2/s to kg/hectare (ha)/yr using following units:

µg/m2/s x 0.000001 g/µg
x 0.001 kg/g
x 10000 m^2/hectare
x 3600 sec/hr
x 8760 hr/yr =kg/ha/yr
or
µg/m^2/s x 315.36 = kg/ha/yr

[b] Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition provided by the U.S. Fish and Wildlife Service, January 2002. A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant.

[c] Total Deposition impacts are based on firing natural gas and fuel oil for 7,760 and 1,000 hours, respectively.

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APPENDIX A

Table A-1. Design Information and Stack Parameters for the PPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 100 % Load

	Ambient/Compressor Inlet Temperature			
Parameter	20 °F	59 °F	72°F	90°F
Combustion Turbine Performance				
Evaporative cooler status/ efficiency (%)	Off	Off	Off	Off
Ambient Relative Humidity (%)	60	60	60	55
Gross power output (MW) - Estimated	200.88	181.74	174.22	157.91
Gross heat rate (Btu/kWh, LHV) - Estimated	8,835	9,100	9,180	9,510
(Btu/kWh, HHV)	9,915	10,085	10,195	10,550
Heat Input (MMBtu/hr, LHV)- calculated	1,775	1,654	1,599	1,502
- provided	1,813	1,649	1,596	1,537
(MMBtu/hr, HHV) - calculated	2,012	1,830	1,771	1,705
(HHV/LHV)	1.110	1.110	1.110	1.110
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039	21,039
(Btu/lb, HHV)	23,345	23,345	23,345	23,345
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)	3,885,997	3,624,720	3,504,549	3,353,000
Temperature (°F)	1,086	1,107	1,118	1,148
Moisture (% Vol.)	7.77	8.39	9.45	11.64
Oxygen (% Vol.)	12.52	12.53	12.32	11.99
Molecular Weight - calculated	28.46	28.39	28.27	28.04
- provided	28.46	28.39	28.27	28.03
Volume 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)	3,885,997	3,624,720	3,504,549	3,353,000
Temperature (°F)	1,086	1,107	1,118	1,148
Molecular weight	28.46	28.39	28.27	28.04
Volume flow (acfm)- calculated	2,567,660	2,433,641	2,379,291	2,339,045
- provided				
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)	1,813	1,649	1,596	1,537
Heat content (Btu/lb, LHV)	21,039	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	86,180	78,380	75,850	73,050
- provided	86,180	78,380	75,850	73,050
Heat content (Btu/cf, LHV)- assumed	920	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,970,805	1,792,431	1,734,574	1,670,542
Stack and Exit Gas Conditions- HRSG				
Stack height (ft)	125	125	125	125
Diameter (ft)	19.0	19.0	19.0	19.0
Temperature (°F)	190	190	190	190
HRSG- Volume flow (acfm)= CT Volume flow (acfm) x [(HRSG Temp. (°F) + 460 K) / (CT Temp. (°F) + 460)]				
CT Volume flow (acfm)	2,567,660	2,433,641	2,379,291	2,339,045
CT Temperature (°F)	1,086	1,107	1,118	1,148
HRSG Temperature (°F)	190	190	190	190
HRSG Volume flow (acfm)	1,079,547	1,009,487	980,063	945,509
Velocity (ft/sec)= Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
Volume flow (acfm)	1,079,547	1,009,487	980,063	945,509
Diameter (ft)	19.0	19.0	19.0	19.0
Velocity (ft/sec)- calculated	63.3	59.2	57.4	55.4

Source: Siemens-Westinghouse, 2000

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Table A-2. Maximum Emissions for Criteria and Other Regulated Pollutants for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 100 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	72°F	90°F
Hours of Operation	8,760	8,760	8,760	8,760
Particulate from CT and SCR				
Particulate from CT= Emission rate (lb/hr) from CT manufacturer (front- and back-half)				
Basis, lb/hr - provided [a]	7.3	6.8	6.5	6.2
Particulate from SCR= Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (=PM10)				
Particulate from conversion of SO_2= SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	5.6	5.1	5.0	4.8
Conversion (%) from SO_2 to SO_3	10	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7	1.7
Particulate (lb/hr)- calculated	1.16	1.06	1.02	0.98
Particulate (lb/hr) from CT + SCR	8.5	7.9	7.5	7.2
(TPY)	37.1	34.4	32.9	31.5
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 use (cf/hr)	1,970,805	1,792,431	1,734,574	1,670,542
Sulfur content (grains/ 100 cf) - assumed [b]	1	1	1	1
lb SO_2/lb S (64/32)	2	2	2	2
Emission rate (lb/hr)- calculated	5.6	5.1	5.0	4.8
(lb/hr)- provided (1 gr/100 cf)	5.5	5.1	5.0	4.7
(TPY)	24.7	22.4	21.7	20.9
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 [a d]	3.5	3.5	3.5	3.5
Moisture (%)	7.77	8.39	9.45	11.64
Oxygen (%)	12.52	12.53	12.32	11.99
Volume Flow (acfm)	2,567,660	2,433,641	2,379,291	2,339,045
Temperature (°F)	1,086	1,107	1,118	1,148
Emission rate (lb/hr)- calculated	25.2	23.1	22.3	21.1
(lb/hr)- provided	25.0	23.1	22.3	21.2
(TPY)	109.5	101.2	97.7	92.9
[Ratio lb/hr provided/calculated]	0.993	1.002	0.998	1.003
Carbon Monoxide (lb/hr)= CO(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} 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- calculated	12.4	12.2	12.4	12.4
Basis, ppmvd @ 15% O2- calculated	10	10	10	10
- provided [a]	10	10	10	10
Moisture (%)	7.77	8.39	9.45	11.64
Oxygen (%)	12.52	12.53	12.32	11.99
Volume Flow (acfm)	2,567,660	2,433,641	2,379,291	2,339,045
Temperature (°F)	1,086	1,107	1,118	1,148
Emission rate (lb/hr)- calculated from given ppmvd	43.8	40.1	38.9	36.8
(lb/hr)- provided	46.0	42.0	41.0	37.0
(TPY)	201.5	184.0	179.6	162.1
[Ratio lb/hr provided/calculated]	1.051	1.048	1.055	1.007
VOCs (lb/hr)= VOC(ppm) 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 (as CH_4)- calculated	2.2	2.2	2.2	2.2
Basis, ppmvd @ 15% O_2- calculated	1.8	1.8	1.8	1.8
- provided [a e]	1.8	1.8	1.8	1.8
Moisture (%)	7.77	8.39	9.45	11.64
Oxygen (%)	12.52	12.53	12.32	11.99
Volume Flow (acfm)	2,567,660	2,433,641	2,379,291	2,339,045
Temperature (°F)	1,086	1,107	1,118	1,148
Emission rate (lb/hr)- calculated	4.5	4.1	4.0	3.8
(lb/hr)- provided	4.7	4.4	4.2	3.8
(TPY)	20.4	19.1	18.4	16.4
[Ratio lb/hr provided/calculated]	1.033	1.055	1.051	0.992
Lead (lb/hr)= NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA
(TPY)	NA	NA	NA	NA
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	2,012	1,830	1,771	1,705
- Duct Burner	0	0	0	0
Total	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	1.61E-06	1.46E-06	1.42E-06	1.36E-06
(TPY)	7.05E-06	6.41E-06	6.20E-06	5.98E-06
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)				
SO_2 emission rate (lb/hr)	5.6	5.1	5.0	4.8
lb H_2SO_4 /lb SO_2 (98/64)	1.53	1.53	1.53	1.53
Conversion to H_2SO_4 (%) (b)	10	10	10	10
Emission Rate (lb/hr)	0.86	0.78	0.76	0.73
(TPY)	3.78	3.43	3.32	3.20

Source: [a] Siemens-Westinghouse, 2000 .

[b] Golder Associates Inc. 1999 .

[c] Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12) .

[d] For NO_X emissions, data originally provided at 25 ppmvd at 15% oxygen.

[e] For VOC emissions, data originally provided at 1.5 ppmvd at 15% oxygen.

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

Table A-3. Maximum Emissions for Other Regulated PSD Pollutants for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 100 % Load

	Ambient/Compressor Inlet Temperature			
Parameter	20 °F	59 °F	72°F	90°F
Hours of Operation	8,760	8,760	8,760	0
Heat Input Rate (MMBtu/hr), HHV- CT	2,012	1,830	1,771	1,705
Duct burner	0	0	0	0
Total	2,012	1,830	1,771	1,705
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, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	2.41E-09	2.20E-09	2.12E-09	2.05E-09
(TPY)	1.06E-08	9.62E-09	9.31E-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, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12) .
Emission factors for metals are questionable and not used .

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-4. Maximum Emissions for Hazardous Air Pollutants for the FPC Hines Energy Center
Siemens-Westinghouse 501P, Dry Low NO_X Combustor, Natural Gas, 100 % Load

	Ambient/Compressor Inlet Temperature			
Parameter	20 °F	59 °F	72°F	90°F
Hours of Operation	8,760	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	2,012	1,830	1,771	1,705
Duct burner	0	0	0	0
Total	2,012	1,830	1,771	1,705
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	8.00E-01	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	1.61E-03	1.46E-03	1.42E-03	1.36E-03
(TPY)	7.05E-03	6.41E-03	6.20E-03	5.98E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Formaldehyde (lb/hr) = 10% of VOC lb/hr				
Emission Rate, lb/10^{12} Btu	2.31E+02	2.31E+02	2.31E+02	2.31E+02
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	4.65E-01	4.23E-01	4.09E-01	3.94E-01
(TPY)	2.04E+00	1.85E+00	1.79E+00	1.73E+00
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	1.00E+01	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	2.01E-02	1.83E-02	1.77E-02	1.71E-02
(TPY)	8.81E-02	8.01E-02	7.76E-02	7.47E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12) .
Emission factors for metals are questionable and not used .

Table A-5. Design Information and Stack Parameters for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 80 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	 59 °F	 90 °F
Combustion Turbine Performance			
Evaporative cooler status/ efficiency (%)	Off	Off	Off
Ambient Relative Humidity (%)	60	60	55
Gross power output (MW) - Estimated	160.80	145.19	127.40
Gross heat rate (Btu/kWh, LHV) - Estimated	9,255	9,516	10,065
(Btu/kWh, HHV)	10,270	10,555	11,170
Heat Input (MMBtu/hr, LHV)- calculated	1,488	1,382	1,282
- provided	1,385	1,382	1,279
(MMBtu/hr, HHV) - calculated	1,537	1,534	1,419
(HHV/LHV)	1.110	1.110	1.110
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,345	23,345	23,345
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)	3,497,411	3,302,475	3,118,517
Temperature (°F)	1,006	1,032	1,083
Moisture (% Vol.)	7.10	7.75	9.14
Oxygen (% Vol.)	13.27	13.25	13.12
Molecular Weight - calculated	28.50	28.43	28.27
- provided	28.51	28.43	28.27
Volume 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)	3,497,411	3,302,475	3,118,517
Temperature (°F)	1,006	1,032	1,083
Molecular weight	28.50	28.43	28.27
Volume flow (acfm)- calculated	2,188,271	2,108,318	2,070,770
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)	1,385	1,382	1,279
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	65,830	65,710	60,790
- provided	65,830	65,710	60,790
Heat content (Btu/cf, LHV)	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,505,432	1,502,688	1,390,175
Stack and Exit Gas Conditions- HRSG			
Stack height (ft)	125	125	125
Diameter (ft)	19.0	19.0	19.0
Temperature (°F)	190	190	190
HRSG- Volume flow (acfm)= CT Volume flow (acfm) x [(HRSG Temp. (°F) + 460 K) / (CT Temp. (°F) + 460)]			
CT Volume flow (acfm)	2,188,271	2,108,318	2,070,770
CT Temperature (°F)	1,006	1,032	1,083
HRSG Temperature (°F)	190	190	190
HRSG Volume flow (acfm)	970,243	918,503	872,327
Velocity (ft/sec)= Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Volume flow (acfm)	970,243	918,503	872,327
Diameter (ft)	19.0	19.0	19.0
Velocity (ft/sec)- calculated	57.0	54.0	51.3

Source: Siemens-Westinghouse, 2000.

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Table A-6. Maximum Emissions for Criteria and Other Regulated Pollutants for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 80 % Load

	Ambient/Compressor Inlet Temperature		
Parameter	20 °F	59 °F	90 °F
Hours of Operation	8,760	8,760	8,760
<u>Particulate from CT and SCR</u>			
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer (front- and back-half)			
Basis, lb/hr - provided [a]	6.6	6.2	5.5
Particulate from SCR= Sulfur trioxide (formed frqm conversion of SO_2) converts to ammonium sulfate (=PM_{10})			
Particulate from conversion of SO_2= SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	4.3	4.3	4.0
Conversion (%) from SO_2 to SO_3	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7
Particulate (lb/hr)- calculated	0.89	0.89	0.82
Particulate (lb/hr) from CT + SCR	7.5	7.1	6.3
(TPY)	32.8	31.0	27.7
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 use (cf/hr)	1,505,432	1,502,688	1,390,175
Sulfur content (grains/ 100 cf) - assumed [b]	1	1	1
lb SO_2/lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	4.3	4.3	4.0
(lb/hr)- provided (1 gr/100 cf)	4.60	4.30	3.80
(TPY)	18.8	18.8	17.4
Nitrogen Oxides (lb/hr)= NO_X(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NO_X) 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 [a,d]	3.5	3.5	3.5
Moisture (%)	7.10	7.75	9.14
Oxygen (%)	13.27	13.25	13.12
Volume Flow (acfm)	2,188,271	2,108,318	2,070,770
Temperature (°F)	1,006	1,032	1,083
Emission rate (lb/hr)- calculated	20.6	19.1	17.7
(lb/hr)- provided	20.6	19.1	17.7
(TPY)	90.2	83.7	77.5
[Ratio lb/hr provided/calculated]	1.001	0.999	1.002
Carbon Monoxide (lb/hr)= CO(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} 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- calculated	11.2	11.1	10.9
Basis, ppmvd @ 15% O_2- calculated	10	10	10
- provided [a]	10	10	10
Moisture (%)	7.10	7.75	9.14
Oxygen (%)	13.27	13.25	13.12
Volume Flow (acfm)	2,188,271	2,108,318	2,070,770
Temperature (°F)	1,006	1,032	1,083
Emission rate (lb/hr)- calculated from given ppr	35.8	33.2	30.7
(lb/hr)- provided	38.0	35.0	33.0
(TPY)	166.4	153.3	144.5
[Ratio lb/hr provided/calculated]	1.062	1.053	1.074
VOCs (lb/hr)= VOC(ppm) 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 (as CH_4)- calculated	2.6	2.5	2.5
Basis, ppmvd @ 15% O_3 - calculated	2.3	2.3	2.3
- provided [a,e]	2.3	2.3	2.3
Moisture (%)	7.10	7.75	9.14
Oxygen (%)	13.27	13.25	13.12
Volume Flow (acfm)	2,188,271	2,108,318	2,070,770
Temperature (°F)	1,006	1,032	1,083
Emission rate (lb/hr)- calculated	4.7	4.4	4.0
(lb/hr)- provided	4.9	4.6	4.2
(TPY)	21.5	20.1	18.4
[Ratio lb/hr provided/calculated]	1.042	1.053	1.040
Lead (lb/hr)= NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA
(TPY)	NA	NA	NA
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	1.23E-06	1.23E-06	1.14E-06
(TPY)	5.38E-06	5.38E-06	4.97E-06
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4/MW SO_2 (98/64)			
SO_2 emission rate (lb/hr)	4.3	4.3	4.0
lb H_2SO_4/lb SO_2 (98/64)	1.53	1.53	1.53
Conversion to H_2SO_4 (%) [b]	10	10	10
Emission Rate (lb/hr)	0.66	0.66	0.61
(TPY)	2.88	2.88	2.66

Source: [a] Siemens-Westinghouse,2000.
[b] Golder Associates Inc. 2000 .
[c] Electric Power Research Institute (EPRI), Electric Utility Trace Subatances Report, 1994 (Table B-12) .
[d] For NO_X emissions, data originally provided at 25 ppmvd at 15% oxygen.
[e] For VOC emissions, data originally provided at 2.8 ppmvd at 15% oxygen.

Table A-7. Maximum Emissions for Other Regulated PSD Pollutants for the FPC HInes Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 80 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	90 °F
Hours of Operation	8,760	8,760	8,760
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, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	1.84E-09	1.84E-09	1.70E-09
(TPY)	8.08E-09	8.06E-09	7.46E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0	0
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0	0
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-8. Maximum Emissions for Hazardous Air Pollutants for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 80 % Load

	Ambient/Compressor Inlet Temperature		
Parameter	20 °F	59 °F	90 °F
Hours of Operation	8,760	8,760	8,760
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	1.23E-03	1.23E-03	1.14E-03
(TPY)	5.38E-03	5.38E-03	4.97E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Formaldehyde (lb/hr) = 10% of VOC lb/hr			
Emission Rate, lb/10^{12} Btu	3.19E+02	3.19E+02	3.19E+02
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	4.90E-01	4.89E-01	4.52E-01
(TPY)	2.15E+00	2.14E+00	1.98E+00
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	1.54E-02	1.53E-02	1.42E-02
(TPY)	6.73E-02	6.72E-02	6.22E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used .

Table A-9. Design Information and Stack Parameters for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 60% Load

	Ambient/Compressor Inlet Temperature			
Parameter	20 °F	59 °F	90 °F	Comment
Combustion Turbine Performance				
Evaporative cooler status/ efficiency (%)	Off	Off	Off	
Ambient Relative Humidity (%)	80	60	55	
Gross power output (MW)	120.13	108.54	93.99	
Gross heat rate (Btu/kWh, LHV)	10,125	10,610	11,075	
(Btu/kWh, HHV)	11,230	11,775	12,295	
Heat Input (MMBtu/hr, LHV)- calculated	1,216	1,152	1,041	
- provided	1,214	1,154	1,061	
(MMBtu/hr, HHV) - estimated	1,347	1,280	1,178	
(HHV/LHV)	1.110	1.110	1.110	
Fuel heating value (Btu/lb, LHV)	21,038	21,038	21,038	
(Btu/lb, HHV)	23,345	23,345	23,345	
(HHV/LHV)	1.110	1.110	1.110	
CT Exhaust Flow				
Mass Flow (lb/hr)	2,821,309	2,687,524	2,572,306	
Temperature (°F)	1,088	1,112	1,083	
Moisture (% Vol.)	7.18	7.89	9.17	
Oxygen (% Vol.)	13.18	13.08	13.08	
Molecular Weight - calculated	28.50	28.42	28.26	
- provided	28.50	28.42	28.27	
Volume 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)	2,821,309	2,687,524	2,572,306	
Temperature (°F)	1,088	1,112	1,083	
Molecular weight	28.50	28.42	28.26	
Volume flow (acfm)- calculated	1,864,103	1,808,271	1,708,519	
- provided				
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)	1,214	1,154	1,061	
Heat content (Btu/lb, LHV)	21,038	21,038	21,038	
Fuel usage (lb/hr)- calculated	57,690	54,830	50,440	
- provided	57,690	54,830	50,440	
Heat content (Btu/cf, LHV)	920	920	920	
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437	
Fuel usage (cf/hr)- calculated	1,319,220	1,253,819	1,153,431	
Stack and Exit Gas Conditions- HRSG				
Stack height (ft)	125	125	125	
Diameter (ft)	19.0	19.0	19.0	
Temperature (°F)	190	190	190	
HRSG- Volume flow (acfm)= CT Volume flow (acfm) x [(HRSG Temp. (°F) + 460 K) / (CT Temp. (°F) + 460)]				
CT Volume flow (acfm)	1,864,103	1,808,271	1,708,519	
CT Temperature (°F)	1,088	1,112	1,083	
HRSG Temperature (°F)	190	190	190	
HRSG Volume flow (acfm)	782,731	747,695	719,726	
Velocity (ft/sec)= Volume flow (acfm) / [((diameter)^2/4) x 3.14159] / 60 sec/min				
Volume flow (acfm)	782,731	747,695	719,726	
Diameter (ft)	19.0	19.0	19.0	
Velocity (ft/sec)- calculated	46.0	44.0	42.3	

Source: Siemens-Westinghouse, 2000.

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Table A-10. Maximum Emissions for Criteria and Other Regulated Pollutants for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 60% Load

	Ambient/Compressor Inlet Temperature		
Parameter	*20 °F*	*59 °F*	*90 °F*
Hours of Operation	3,000	3,000	3,000
Particulate from CT and SCR			
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer (front- and back-half)			
Basis, lb/hr (a)	5.3	5.1	4.8
Particulate from 5CR= Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (=PM10)			
Particulate from conversion of SO_2= SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	3.8	3.6	3.3
Conversion (%) from SO_2 to SO_3	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7
Particulate (lb/hr)- calculated	0.78	0.74	0.68
Particulate (lb/hr) from CT + SCR	6.1	5.8	5.5
(TPY)	9.1	8.8	8.2
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 use (cf/hr)	1,319,220	1,253,819	1,153,431
Sulfur content (grains/ 100 cf) - assumed (b)	1	1	1
lb SO_2/lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	3.8	3.6	3.3
(lb/hr)- provided (1 gr/100 cf)	3.75	3.56	3.27
(TPY)	5.7	5.4	4.9
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 (a) (d)	3.5	3.5	3.5
Moisture (%)	7.18	7.89	9.17
Oxygen (%)	13.18	13.08	13.08
Volume Flow (acfm)	1,864,103	1,808,271	1,708,519
Temperature (°F)	1,088	1,112	1,083
Emission rate (lb/hr)- calculated	16.8	15.9	14.7
(lb/hr)- provided	16.8	15.9	14.6
(TPY)	25.2	23.9	21.9
[Ratio lb/hr provided/calculated]	1.000	0.999	0.996
Carbon Monoxide (lb/hr)= CO(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} 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- calculated	56.8	56.8	55.1
Basis, ppmvd @ 15% O2- calculated	50	50	50
- provided (a)	50	50	50
Moisture (%)	7.18	7.89	9.17
Oxygen (%)	13.18	13.08	13.08
Volume Flow (acfm)	1,864,103	1,808,271	1,708,519
Temperature (°F)	1,088	1,112	1,083
Emission rate (lb/hr)- calculated from given ppm	146.1	138.5	127.5
(lb/hr)- provided	154.0	146.0	134.0
(TPY)	231.0	219.0	201.0
[Ratio lb/hr provided/calculated]	1.054	1.054	1.051
VOCs (lb/hr)= VOC(ppm) 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 (as CH_4)- calculated	3.4	3.4	3.3
Basis, ppmvd @ 15% O2- calculated	3.0	3.0	3.0
- provided (a) (e)	3.0	3.0	3.0
Moisture (%)	7.18	7.89	9.17
Oxygen (%)	13.18	13.08	13.08
Volume Flow (acfm)	1,864,103	1,808,271	1,708,519
Temperature (°F)	1,088	1,112	1,083
Emission rate (lb/hr)- calculated	5.0	4.7	4.4
(lb/hr)- provided	5.3	5.0	4.6
(TPY)	8.0	7.5	6.9
[Ratio lb/hr provided/calculated]	1.058	1.053	1.052
Lead (lb/hr)= NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA
(TPY)	NA	NA	NA
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu (c)	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	1.08E-06	1.02E-06	9.42E-07
(TPY)	1.62E-06	1.54E-06	1.41E-06
Sulfuric Acid Mist = SO2 emission rate (lb/hr) x conversion rate of SO2 to H_2SO_4 (%) x MW H_2SO_4/MW SO_2 (98/64)			
SO2 emission rate (lb/hr)	3.8	3.6	3.3
lb H_2SO_4/lb SO_2 (98/64)	1.53	1.53	1.53
Conversion to H_2SO_4 (%) (b)	10	10	10
Emission Rate (lb/hr)	0.58	0.55	0.50
(TPY)	0.87	0.82	0.76

Source: (a) Siemens-Westinghouse, 2000.
(b) Golder Associates Inc. 2000 .
(c) Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12) .
(d) For NOx emissions, data originally provided at 25 ppmvd at 15% oxygen.

Table A-11. Maximum Emissions for Other Regulated PSD Pollutants for the FPC HInes Energy Center
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 60% Load

	Ambient/Compressor Inlet Temperature		
Parameter	20 °F	59 °F	90 °F
Hours of Operation	3,000	3,000	3,000
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, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	1.62E-09	1.54E-09	1.41E-09
(TPY)	2.42E-09	2.30E-09	2.12E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12) .
Emission factors for metals are questionable and not used .

Table A-12. Maximum Emissions for Hazardous Air Pollutants for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 60% Load

	Ambient/Compressor Inlet Temperature		
Parameter	20 °F	59 °F	90 °F
Hours of Operation	3,000	3,000	3,000
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	1.08E-03	1.02E-03	9.42E-04
(TPY)	1.62E-03	1.54E-03	1.41E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Formaldehyde (lb/hr) = 10% of VOC lb/hr			
Emission Rate, lb/10^{12} Btu	3.94E+02	3.94E+02	3.94E+02
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	5.30E-01	5.04E-01	4.63E-01
(TPY)	7.95E-01	7.56E-01	6.95E-01
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,347	1,280	1,178
Emission Rate (lb/hr)	1.35E-02	1.28E-02	1.18E-02
(TPY)	2.02E-02	1.92E-02	1.77E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-13. Design Information and Stack Parameters for FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 100 % Load

	Turbine Inlet Temperature			
Parameter	20 °F	59 °F	72 °F	105 °F
Combustion Turbine Performance				
Gross power output (MW) - Estimated	191.9	184.5	178.4	163.1
Gross heat rate (Btu/kWh, LHV) - Calculated	9,513	9,101	9,109	9,094
(Btu/kWh, HHV) - Calculated	10,945	10,470	10,480	10,463
Heat Input (MMBtu/hr, LHV) - Calculated	1,825	1,679	1,625	1,483
(MMBtu/hr, HHV) - Calculated	2,100	1,932	1,870	1,707
(MMBtu/hr, HHV) - Provided	2,100	1,932	1,870	1,707
Fuel heating value (Btu/lb, LHV)	17,290	17,290	17,290	17,290
(Btu/lb, HHV)	19,892	19,892	19,892	19,892
(HHV/LHV)	1.150	1.150	1.150	1.150
CT Exhaust Flow				
Mass Flow (lb/hr)	3,826,829	3,680,420	3,558,433	3,253,093
	3,826,829	3,680,420	3,558,433	3,253,093
Temperature (°F) - Estimated	1,070	1,100	1,110	1,130
Moisture (% Vol.)	7.12	7.74	8.79	11.04
Oxygen (% Vol.)	11.99	11.99	11.78	11.40
Molecular Weight	28.78	28.68	28.56	28.32
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)	1,825	1,679	1,625	1,483
Heat content (Btu/lb, LHV)	17,290	17,290	17,290	17,290
Fuel usage (lb/hr)- calculated	105,570	97,130	94,000	85,790
- provided	105,570	97,130	94,000	85,790
(gallons/hr) - calculated lb/gal= 7.1	14,869	13,680	13,239	12,083
HRSG Stack				
CT - Stack height (ft)	125	125	125	125
Diameter (ft)	19	19	19	19
Turbine Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,826,829	3,680,420	3,558,433	3,253,093
Temperature (°F)	1,070	1,100	1,110	1,130
Molecular weight	28.78	28.68	28.56	28.32
Volume flow (acfm)- calculated	2,475,210	2,434,870	2,379,489	2,222,073
(ft3/s)- calculated	41,254	40,581	39,658	37,035
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	270	270	270	270
CT volume flow (acfm)	1,180,983	1,139,394	1,106,387	1,020,197
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	69.4	67.0	65.0	60.0

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: Siemens/Westinghouse 2000,

Table A-14. Maximum Emissions for Criteria Pollutants for FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 100 % Load

	Turbine Inlet Temperature			
Parameter	20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	43	39.6	38.3	34.8
Emission rate (lb/hr)- provided	43.0	39.6	38.3	34.8
Particulate from SCR= Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (=PM_{10})				
Particulate from conversion of SO_2= SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	105.6	97.1	94.0	85.8
Conversion (%) from SO_2 to SO_3	10	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7	1.7
Particulate (lb/hr)- calculated	21.77	20.03	19.39	17.69
Particulate (lb/hr) from CT + SCR	64.8	59.6	57.7	52.5
Particulate (tons/year) from CT + SCR	32.4	29.8	28.8	26.2
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%	0.05%
Fuel use (lb/hr)	105,570	97,130	94,000	85,790
lb SO_2/lb S (64/32)	2	2	2	2
Emission rate (lb/hr) - calculated	105.6	97.1	94.0	85.8
- provided	95	95	94	86
(TPY)	52.79	48.57	47.00	42.90
Nitrogen Oxides (lb/hr) = NO_X(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	12	12	12	12
Moisture (%)	7.12	7.74	8.79	11.04
Oxygen (%)	11.99	11.99	11.78	11.4
Turbine Flow (acfm)	1,180,983	1,139,394	1,106,387	1,020,197
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	92.3	87.5	84.9	77.3
- provided	92.3	87.5	84.9	77.3
(TPY)	46.2	43.8	42.4	38.7
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	30
Moisture (%)	7.12	7.74	8.79	11.04
Turbine Flow (acfm)	1,180,983	1,139,394	1,106,387	1,020,197
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	103.8	99.4	95.5	85.8
- provided	112.0	106.0	102.0	91.0
(TPY)	56.0	53.0	51.0	45.5
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	10	10	10	10
Turbine Flow (acfm)	1,180,983	2,434,870	2,379,489	2,222,073
Turbine Exhaust Temperature (°F)	270	1,100	1,110	1,130
Emission rate (lb/hr) - calculated	21.28	20.53	19.93	18.38
- provided	22.0	21.0	21.0	19.0
(TPY)	11.0	10.5	10.5	9.5
Lead (lb/hr)= NA				
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8	10.8
Emission rate (lb/hr)	0.0227	0.0209	0.0202	0.0184
(TPY)	0.0113	0.0104	0.0101	0.0092

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

Source: Siemens/Westinghouse, 2000; Golder Associates, 2000; EPA, 1996 (AP-42 draft revisions)

Table A-15. Maximum Emissions for Other Regulated PSD Pollutants for FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 100 % Load

Hours of Operation	1,000	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	3.80E-04
Heat Input Rate (MMBtu/hr)	2.10E+03	1.93E+03	1.87E+03	1.87E+03
Emission Rate (lb/hr)	7.98E-07	7.34E-07	7.11E-07	7.11E-07
(TPY)	3.99E-07	3.67E-07	3.55E-07	3.55E-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	0.331
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	6.95E-04	6.40E-04	6.19E-04	6.19E-04
(TPY)	3.48E-04	3.20E-04	3.09E-04	3.09E-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	32.54
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	6.83E-02	6.29E-02	6.08E-02	6.08E-02
(TPY)	3.42E-02	3.14E-02	3.04E-02	3.04E-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	2.07E+02	2.07E+02	2.07E+02	2.07E+02
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	4.34E-01	3.99E-01	3.87E-01	3.87E-01
(TPY)	2.17E-01	2.00E-01	1.93E-01	1.93E-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	6.26E-01
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	1.31E-03	1.21E-03	1.17E-03	1.17E-03
(TPY)	6.57E-04	6.05E-04	5.85E-04	5.85E-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)	105,570	97,130	94,000	85,790
Sulfur (lb/hr)	52.79	48.57	47.00	42.90
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (d)	10	10	10	10
Emission Rate (lb/hr)	16.17	14.87	14.39	13.14
(TPY)	8.08	7.44	7.20	6.57

Sources:
[a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-16. Maximum Emissions for Hazardous Air Pollutants for FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 100 % Load

	0			
Parameter	0	0	0	0
Hours of Operation	1,000	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	7.91E+00
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	1.66E-02	1.53E-02	1.48E-02	1.48E-02
(TPY)	8.31E-03	7.64E-03	7.40E-03	7.40E-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	1.1
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	2.31E-03	2.13E-03	2.06E-03	2.06E-03
(TPY)	1.15E-03	1.06E-03	1.03E-03	1.03E-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	3.24	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	6.80E-03	6.26E-03	6.06E-03	6.06E-03
(TPY)	3.40E-03	3.13E-03	3.03E-03	3.03E-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	6.76
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	1.42E-02	1.31E-02	1.26E-02	1.26E-02
(TPY)	7.10E-03	6.53E-03	6.32E-03	6.32E-03
Formaldehyde (lb/hr) = 10% of VOC lb/hr				
Emission Rate, lb/10^{12} Btu	1.05E+03	1.05E+03	1.05E+03	1.05E+03
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	2.20E+00	2.02E+00	1.96E+00	1.96E+00
(TPY)	1.10E+00	1.01E+00	9.79E-01	9.79E-01
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	37
Heat Input Rate (MMBtu/hr)	2.10E+03	1.93E+03	1.87E+03	1.87E+03
Emission Rate (lb/hr)	7.77E-02	7.15E-02	6.92E-02	6.92E-02
(TPY)	3.88E-02	3.57E-02	3.46E-02	3.46E-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	432
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	9.07E-01	8.35E-01	8.08E-01	8.08E-01
(TPY)	4.54E-01	4.17E-01	4.04E-01	4.04E-01
Nickel (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	86.3	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	1.81E-01	1.67E-01	1.61E-01	1.61E-01
(TPY)	9.06E-02	8.34E-02	8.07E-02	8.07E-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	3.00E+02
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	0.629999532	0.579632988	0.5609544	0.5609544
(TPY)	0.314999766	0.289816494	0.2804772	0.2804772
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	23
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	4.83E-02	4.44E-02	4.30E-02	4.30E-02
(TPY)	2.41E-02	2.22E-02	2.15E-02	2.15E-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	237
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	4.98E-01	4.58E-01	4.43E-01	4.43E-01
(TPY)	2.49E-01	2.29E-01	2.22E-01	2.22E-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 FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 80 % Load

	Turbine Inlet Temperature			
Parameter	20 °F	59 °F	72 °F	105 °F
Combustion Turbine Performance				
Gross power output (MW) - Estimated	153.5	147.6	142.7	130.5
Gross heat rate (Btu/kWh, LHV) - Calculated	9,642	9,295	9,335	9,412
(Btu/kWh, HHV) - Calculated	10,707	10,321	10,366	10,452
Heat Input (MMBtu/hr, LHV) - Calculated	1,480	1,372	1,332	1,228
(MMBtu/hr, HHV) - Calculated	1,644	1,524	1,480	1,364
(MMBtu/hr, HHV) - Provided	1,644	1,524	1,480	1,364
Fuel heating value (Btu/lb, LHV)	17,290	17,290	17,290	17,290
(Btu/lb, HHV)	19,200	19,200	19,200	19,200
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)	3,800,715	3,589,967	3,459,546	3,179,611
	3,800,715	3,589,967	3,459,546	3,179,611
Temperature (°F) - Estimated	1,120	1,140	1,150	1,170
Moisture (% Vol.)	5.85	6.53	7.6	9.9
Oxygen (% Vol.)	13.42	13.38	13.17	12.73
Molecular Weight	28.81	28.73	28.61	28.36
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)	1,480	1,372	1,332	1,228
Heat content (Btu/lb, LHV)	17,290	17,290	17,290	17,290
Fuel usage (lb/hr)- calculated	85,600	79,360	77,060	71,030
- provided	85,600	79,360	77,060	71,030
(gallons/hr) - calculated lb/gal= 7.1	12,056	11,177	10,854	10,004
HRSG Stack				
CT - Stack height (ft)	125	125	125	125
Diameter (ft)	19	19	19	19
Turbine Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,800,715	3,589,967	3,459,546	3,179,611
Temperature (°F)	1,120	1,140	1,150	1,170
Molecular weight	28.81	28.73	28.61	28.36
Volume flow (acfm)- calculated	2,535,697	2,431,994	2,368,159	2,223,331
(ft3/s)- calculated	42,262	40,533	39,469	37,056
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	270	270	270	270
CT volume flow (acfm)	1,171,556	1,109,597	1,073,761	995,725
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	68.9	65.2	63.1	58.5

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: Siemens/Westinghouse 2000,

Table A-18. Maximum Emissions for Criteria Pollutants for FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 80 % Load

	Turbine Inlet Temperature			
Parameter	20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	34.7	32.2	31.2	29.7
Emission rate (lb/hr)- provided	34.7	32.2	31.2	29.7
Particulate from SCR= Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (=PM_{10})				
Particulate from conversion of SO_2= SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	85.6	79.4	77.1	71.0
Conversion (%) from SO_2 to SO_3	10	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7	1.7
Particulate (lb/hr)- calculated	17.66	16.37	15.89	14.65
Particulate (lb/hr) from CT + SCR	52.4	48.6	47.1	44.3
Particulate (tons/year) from CT + SCR	26.2	24.3	23.5	22.2
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%	0.05%
Fuel use (lb/hr)	85,600	79,360	77,060	71,030
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr) - calculated	85.6	79.4	77.1	71.0
- provided	86	79	77	71
(TPY)	42.80	39.68	38.53	35.52
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	12	12	12	12
Moisture (%)	5.85	6.53	7.6	9.9
Oxygen (%)	13.42	13.38	13.17	12.73
Turbine Flow (acfm)	1,171,556	1,109,597	1,073,761	995,725
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	77.2	72.0	69.5	64.0
- provided	77.2	72.0	69.5	64.0
(TPY)	38.6	36.0	34.7	32.0
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	30
Moisture (%)	5.85	6.53	7.6	9.9
Turbine Flow (acfm)	1,171,556	1,109,597	1,073,761	995,725
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	104.3	98.1	93.9	84.9
- provided	111.0	103.0	100.0	89.0
(TPY)	55.5	51.5	50.0	44.5
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	10	10	10	10
Turbine Flow (acfm)	1,171,556	2,431,994	2,368,159	2,223,331
Turbine Exhaust Temperature (°F)	270	1,140	1,150	1,170
Emission rate (lb/hr) - calculated	21.11	19.99	19.35	17.94
- provided	21.0	22.0	21.0	19.0
(TPY)	10.5	11.0	10.5	9.5
Lead (lb/hr)= NA				
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8	10.8
Emission rate (lb/hr)	0.0178	0.0165	0.0160	0.0147
(TPY)	0.0089	0.0082	0.0080	0.0074

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

Source: Siemens/Westinghouse, 2000; Golder Associates, 2000; EPA, 1996 (AP-42 draft revisions)

Table A-19. Maximum Emissions for Other Regulated PSD Pollutants for FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 80 % Load

Parameter	Turbine Inlet Temperature			
	20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	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	3.80E-04
Heat Input Rate (MMBtu/hr)	1.64E+03	1.52E+03	1.48E+03	1.48E+03
Emission Rate (lb/hr)	6.25E-07	5.79E-07	5.62E-07	5.62E-07
(TPY)	3.12E-07	2.90E-07	2.81E-07	2.81E-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	0.331
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	5.44E-04	5.04E-04	4.90E-04	4.90E-04
(TPY)	2.72E-04	2.52E-04	2.45E-04	2.45E-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	32.54
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	5.35E-02	4.96E-02	4.81E-02	4.81E-02
(TPY)	2.67E-02	2.48E-02	2.41E-02	2.41E-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	2.14E+02	2.14E+02	2.14E+02	2.14E+02
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	3.52E-01	3.26E-01	3.17E-01	3.17E-01
(TPY)	1.76E-01	1.63E-01	1.58E-01	1.58E-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	6.26E-01
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	1.03E-03	9.54E-04	9.26E-04	9.26E-04
(TPY)	5.14E-04	4.77E-04	4.63E-04	4.63E-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)	85,600	79,360	77,060	71,030
Sulfur (lb/hr)	42.80	39.68	38.53	35.52
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) [d]	10	10	10	10
Emission Rate (lb/hr)	13.11	12.15	11.80	10.88
(TPY)	6.55	6.08	5.90	5.44

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-20. Maximum Emissions for Hazardous Air Pollutants for FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 80 % Load

	Turbine Inlet Temperature			
Parameter	20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	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	7.91E+00
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	1.30E-02	1.21E-02	1.17E-02	1.17E-02
(TPY)	6.50E-03	6.03E-03	5.85E-03	5.85E-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	1.1
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	1.81E-03	1.68E-03	1.63E-03	1.63E-03
(TPY)	9.04E-04	8.38E-04	8.14E-04	8.14E-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	3.24
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	5.33E-03	4.94E-03	4.79E-03	4.79E-03
(TPY)	2.66E-03	2.47E-03	2.40E-03	2.40E-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	6.76
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	1.11E-02	1.03E-02	1.00E-02	1.00E-02
(TPY)	5.56E-03	5.15E-03	5.00E-03	5.00E-03
Formaldehyde (lb/hr) = 10% of VOC lb/hr				
Emission Rate, lb/10^{12} Btu	1.28E+03	1.28E+03	1.28E+03	1.28E+03
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	2.10E+00	1.95E+00	1.89E+00	1.89E+00
(TPY)	1.05E+00	9.73E-01	9.45E-01	9.45E-01
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	37
Heat Input Rate (MMBtu/hr)	1.64E+03	1.52E+03	1.48E+03	1.48E+03
Emission Rate (lb/hr)	6.08E-02	5.64E-02	5.47E-02	5.47E-02
(TPY)	3.04E-02	2.82E-02	2.74E-02	2.74E-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	432
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	7.10E-01	6.58E-01	6.39E-01	6.39E-01
(TPY)	3.55E-01	3.29E-01	3.20E-01	3.20E-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	86.3
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	1.42E-01	1.31E-01	1.28E-01	1.28E-01
(TPY)	7.09E-02	6.57E-02	6.38E-02	6.38E-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	3.00E+02
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	0.493056	0.4571136	0.4438656	0.4438656
(TPY)	0.246528	0.2285568	0.2219328	0.2219328
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	23
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	3.78E-02	3.50E-02	3.40E-02	3.40E-02
(TPY)	1.89E-02	1.75E-02	1.70E-02	1.70E-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	237
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	3.90E-01	3.61E-01	3.51E-01	3.51E-01
(TPY)	1.95E-01	1.81E-01	1.75E-01	1.75E-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 FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 65 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Combustion Turbine Performance				
Gross power output (MW) - Estimated	124.7	119.9	116.0	106.0
Gross heat rate (Btu/kWh, LHV) - Calculated	9,997	9,733	9,834	10,036
(Btu/kWh, HHV) - Calculated	11,101	10,808	10,920	11,145
Heat Input (MMBtu/hr, LHV) - Calculated	1,247	1,167	1,140	1,064
(MMBtu/hr, HHV) - Calculated	1,385	1,296	1,266	1,182
(MMBtu/hr, HHV) - Provided	1,385	1,296	1,266	1,182
Fuel heating value (Btu/lb, LHV)	17,290	17,290	17,290	17,290
(Btu/lb, HHV)	19,200	19,200	19,200	19,200
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)	3,491,217	3,298,903	3,219,964	3,009,818
	3,491,217	3,298,903	3,219,964	3,009,818
Temperature (°F) - Estimated	1,170	1,180	1,190	1,200
Moisture (% Vol.)	4.99	5.71	6.78	9.08
Oxygen (% Vol.)	14.12	14.04	13.83	13.41
Molecular Weight	28.87	28.79	28.66	28.41
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)	1,247	1,167	1,140	1,064
Heat content (Btu/lb, LHV)	17,290	17,290	17,290	17,290
Fuel usage (lb/hr)- calculated	72,110	67,520	65,960	61,540
- provided	72,110	67,520	65,960	61,540
(gallons/hr) - calculated lb/gal= 7.1	10,156	9,510	9,290	8,668
HRSG Stack				
CT - Stack height (ft)	125	125	125	125
Diameter (ft)	19	19	19	19
Turbine Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,491,217	3,298,903	3,219,964	3,009,818
Temperature (°F)	1,170	1,180	1,190	1,200
Molecular weight	28.87	28.79	28.66	28.41
Volume flow (acfm)- calculated	2,397,803	2,286,301	2,255,019	2,139,484
(ft3/s)- calculated	39,963	38,105	37,584	35,658
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2/4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	270	270	270	270
CT volume flow (acfm)	1,073,863	1,017,683	997,675	940,858
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	63.1	59.8	58.6	55.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: Siemens/Westinghouse 2000,

Table A-22. Maximum Emissions for Criteria Pollutants for FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 65 % Load

	Turbine Inlet Temperature			
Parameter	20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes $H_2 SO_4$), lb/hr	28.6	27	26.3	24.5
Emission rate (lb/hr)- provided	28.6	27.0	26.3	24.5
Particulate from SCR= Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (=PM_{10})				
Particulate from conversion of SO_2= SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2 SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	72.1	67.5	66.0	61.5
Conversion (%) from SO_2 to SO_3	10	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2 SO_4$/ SO_3 (132/80)	1.7	1.7	1.7	1.7
Particulate (lb/hr)- calculated	14.87	13.93	13.60	12.69
Particulate (lb/hr) from CT + SCR	43.5	40.9	39.9	37.2
Particulate (tons/year) from CT + SCR	21.7	20.5	20.0	18.6
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%	0.05%
Fuel use (lb/hr)	72,110	67,520	65,960	61,540
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr) - calculated	72.1	67.5	66.0	61.5
- provided	72	68	66	62
(TPY)	36.06	33.76	32.98	30.77
Nitrogen Oxides (lb/hr) = NO_X(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NO_X) 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	12	12	12	12
Moisture (%)	4.99	5.71	6.78	9.08
Oxygen (%)	14.12	14.04	13.83	13.41
Turbine Flow (acfm)	1,073,863	1,017,683	997,675	940,858
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	64.9	60.8	59.4	55.4
- provided	64.9	60.8	59.4	55.4
(TPY)	32.5	30.4	29.7	27.7
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	30
Moisture (%)	4.99	5.71	6.78	9.08
Turbine Flow (acfm)	*1,073,863*	*1,017,683*	*997,675*	*940,858*
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	96.5	90.8	88.0	80.9
- provided	101.0	94.0	92.0	86.0
(TPY)	50.5	47.0	46.0	43.0
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	10	10	10	10
Turbine Flow (acfm)	1,073,863	2,286,301	2,255,019	2,139,484
Turbine Exhaust Temperature (°F)	270	1,180	1,190	1,200
Emission rate (lb/hr) - calculated	19.35	18.34	17.98	16.95
- provided	*20.0*	*19.0*	*18.0*	*19.0*
(TPY)	10.0	9.5	9.0	9.5
Lead (lb/hr)= NA				
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8	10.8
Emission rate (lb/hr)	0.0150	0.0140	0.0137	0.0128
(TPY)	0.0075	0.0070	0.0068	0.0064

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

Source: Siemens/Westinghouse, 2000; Golder Associates, 2000; EPA, 1996 (AP-42 draft revisions)

Table A-23. Maximum Emissions for Other Regulated PSD Pollutants for FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 65 % Load

	Turbine Inlet Temperature			
Parameter	20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	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	3.80E-04
Heat Input Rate (MMBtu/hr)	1.38E+03	1.30E+03	1.27E+03	1.27E+03
Emission Rate (lb/hr)	5.26E-07	4.93E-07	4.81E-07	4.81E-07
(TPY)	2.63E-07	2.46E-07	2.41E-07	2.41E-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	0.331
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	4.58E-04	4.29E-04	4.19E-04	4.19E-04
(TPY)	2.29E-04	2.15E-04	2.10E-04	2.10E-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	32.54
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	4.51E-02	4.22E-02	4.12E-02	4.12E-02
(TPY)	2.25E-02	2.11E-02	2.06E-02	2.06E-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	2.14E+02	2.14E+02	2.14E+02	2.14E+02
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	2.97E-01	2.78E-01	2.71E-01	2.71E-01
(TPY)	1.48E-01	1.39E-01	1.36E-01	1.36E-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	6.26E-01
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	8.67E-04	8.12E-04	7.93E-04	7.93E-04
(TPY)	4.33E-04	4.06E-04	3.96E-04	3.96E-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)	72,110	67,520	65,960	61,540
Sulfur (lb/hr)	36.06	33.76	32.98	30.77
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) [d]	10	10	10	10
Emission Rate (lb/hr)	11.04	10.34	10.10	9.42
(TPY)	5.52	5.17	5.05	4.71

Sources:
[a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-24. Maximum Emissions for Hazardous Air Pollutants for FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 65 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Hours of Operation	*1,000*	*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	7.91E+00
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	1.10E-02	1.03E-02	1.00E-02	1.00E-02
(TPY)	5.48E-03	5.13E-03	5.01E-03	5.01E-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	1.1
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	1.52E-03	1.43E-03	1.39E-03	1.39E-03
(TPY)	7.61E-04	7.13E-04	6.97E-04	6.97E-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	3.24
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	4.49E-03	4.20E-03	4.10E-03	4.10E-03
(TPY)	2.24E-03	2.10E-03	2.05E-03	2.05E-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	6.76
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	9.36E-03	8.76E-03	8.56E-03	8.56E-03
(TPY)	4.68E-03	4.38E-03	4.28E-03	4.28E-03
Formaldehyde (lb/hr) = 10% of VOC lb/hr				
Emission Rate, lb/10^{12} Btu	1.44E+03	1444.552304	1444.552304	1444.552304
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	2.00E+00	1.87E+00	1.83E+00	1.83E+00
(TPY)	1.00E+00	9.36E-01	9.15E-01	9.15E-01
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	37
Heat Input Rate (MMBtu/hr)	1.38E+03	1.30E+03	1.27E+03	1.27E+03
Emission Rate (lb/hr)	5.12E-02	4.80E-02	4.69E-02	4.69E-02
(TPY)	2.56E-02	2.40E-02	2.34E-02	2.34E-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	432
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	5.98E-01	5.60E-01	5.47E-01	5.47E-01
(TPY)	2.99E-01	2.80E-01	2.74E-01	2.74E-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	86.3
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	1.19E-01	1.12E-01	1.09E-01	1.09E-01
(TPY)	5.97E-02	5.59E-02	5.46E-02	5.46E-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	3.00E+02
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	0.4153536	0.3889152	0.3799296	0.3799296
(TPY)	0.2076768	0.1944576	0.1899648	0.1899648
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	23
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	3.18E-02	2.98E-02	2.91E-02	2.91E-02
(TPY)	1.59E-02	1.49E-02	1.46E-02	1.46E-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	237
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	3.28E-01	3.07E-01	3.00E-01	3.00E-01
(TPY)	1.64E-01	1.54E-01	1.50E-01	1.50E-01

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

Table A-25 Summary of Maximum Potential Annual Emissions for the CT/HRSG

Pollutant		Annual Emissions (tons/year)[a]			Maximum Emissions (tons/year)[b]				PSD Significant Emission Rates
		Natural Gas	Natural Gas	Distillate Oil	Case A	Case B	Case C	Case D	
	Load:	100%	60%	100%					
	Hours:	8,760	3,000	1,000					
One Combustion Turbine- Combined Cycle									
SO_2		22.4	5.4	48.6	22.4	20.1	68.4	66.1	40
PM/PM_{10}		34.4	8.8	29.8	34.4	31.4	60.3	57.3	25/15
NO_x		101	24	44	101.2	90.4	133.4	122.6	40
CO		184	219	53	184.0	340.0	216.0	372.0	100
VOC (as methane)		19.1	7.5	10.5	19.1	20.0	27.4	28.4	40
Sulfuric Acid Mist		3.4	0.8	7.4	3.4	3.1	10.5	10.1	7
Laad		0	0.00E+00	1.04E-02	0.0E+00	0.0E+00	1.0E-02	1.0E-02	0.6
Mercury		6.41E-06	1.54E-06	6.05E-04	6.4E-06	5.8E-06	6.1E-04	6.1E-04	0.1
Total HAPs		1.93	0.77	1.80	1.9	2.0	3.5	3.6	25
Two Combustion Turbines- Combined Cycle									
SO_2		44.9	10.7	97.1	44.9	40.2	136.9	132.3	40
PM/PM_{10}		69	18	60	69	63	121	115	25/15
NO_x		202	48	88	202	181	267	245	40
CO		368	438	106	368	680	432	744	100
VOC (as methane)		38.1	15.0	21.0	38.1	40.1	54.8	56.7	40
Sulfuric Acid Mist		6.9	1.65	14.87	6.87	6.16	20.96	20.25	7
Lead		0.00E+00	0.00E+00	2.09E-02	0.00E+00	0.00E+00	2.09E-02	2.09E-02	0.6
Mercury		1.28E-05	3.07E-06	1.21E-03	1.28E-05	1.15E-05	1.22E-03	1.22E-03	0.1
Total HAPs		3.9	1.55	3.60	3.87	4.09	7.02	7.25	25

[a] Based on 59 °F compressor inlet air temperature

APPENDIX B

B.1 NEW SOURCE PERFORMANCE STANDARDS

BACT is a case-by-case emission limitation for each applicable pollutant, based on the maximum degree of emission reduction after taking into account the energy, environmental, and economic impacts, and other costs. The BACT cannot be any less stringent than any applicable new source performance standards (NSPS) and consideration must be given to the applicable NSPS in the determination of BACT. This requirement also applies for any applicable National Emission Standard for Hazardous Air Pollutants promulgated under 40 CFR Part 61. For combustion turbines the applicable NSPS is 40 CFR Part 60, Subpart GG Standards of Performance for Stationary Gas Turbines.

B.1.1 SUBPART GG

The NSPS regulations (40 CFR, Subpart GG) applicable to gas turbines apply to:

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100 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 combustion turbines proposed for the project and are the most stringent provision of the NSPS. These requirements are summarized in Table B-1 and were considered in the BACT analysis.

As noted from Table B-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; for a fuel-bound nitrogen concentration of 0.03 percent, the NSPS is increased by 0.0012 percent or 12 parts per million (ppm). The NSPS NO_x emission limit adjustment is not affected by natural gas combustion.

B.2 BEST AVAILABLE CONTROL TECHNOLOGY

The "top-down" analysis for determining BACT, as provided for in EPA's Draft 1990 New Source Review Workshop Manual was considered in evaluating BACT for the Project. The procedure involves 5 steps: identification of control technologies, elimination of technically infeasible control technologies, a ranking of the control technologies, an evaluation of the effective control technologies and the selection of BACT.

The identification of control technologies is developed from the information obtained from BACT/LAER Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina. While these data are comprehensive it is often not up to date with the most recent BACT/LAER decisions and separate contact with state agencies is required. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

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

The elimination of infeasible technologies is based on those engineering aspects that would preclude a technology's use due to physical, chemical or other engineering consideration. Control technologies that are technically feasible are ranked by control effectiveness, with determination of the environmental, economic and energy costs and benefits of the control technologies. This information forms the basis for the case-by-case consideration of environmental, energy and economic impacts. The "top" feasible control alterable is selected unless it can be rejected based on economic, environmental or energy considerations. This section of Appendix B presents information related to the proposed BACT emission limitation.

B.2.1 NITROGEN OXIDES

Identification of NO_x Control Technologies

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

Table B-2 presents a listing of the lowest achievable emission rates/best available control technology (LAER/BACT) decisions made by state environmental agencies and EPA regional offices for gas turbines including duct firing. This table was developed from the information obtained from BACT/LAER Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina, and EPA Region 4's summary of recent national CT BACT projects. EPA Region 4's summary data was pulled from the following internet site: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001).

Historically, the most stringent NO_x controls for CTs established as LAER/BACT by state agencies were combustion controls with selective catalytic reduction (SCR) and combustion controls alone. SCR is a post-combustion control, while advanced dry low-NO_x combustors minimize the formation of NO_x in the combustion process. When SCR has been employed, dry low-NO_x combustion technology is used to minimize the NO_x emissions formed in the combustion process.

Wet injection was the first combustion technology introduced for combustion turbines (pre-1980's) and was the primary method of reducing NO_x emissions from CTs prior to the 1990's. Indeed, this method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O_2 and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd (corrected to 15-percent O_2) when burning natural gas. Wet injection is still the only means of reducing NO_x formation in the combustion process when firing oil.

The dry low-NO_x combustion technology has been developed and made available since the early 1990's for gas turbines to achieve emission levels of 25 ppmvd corrected to 15-percent O_2. More recently, however, CT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 9ppmvd (corrected to 15-percent O_2) when firing natural gas.

SCR is an available and demonstrated control technology for NO_x control or combined cycle units, which has been installed or permitted in over 100 projects. Beginning in the late 1980s and early 1990s, SCR was initially installed on cogeneration facilities with capacities of 50 MW or less. Most of these projects were in California. Many of these initial SCR projects were located in the Southern California NO_2 nonattainment area where SCR was required not as BACT but as LAER, a more stringent requirement. As noted previously, there are distinct regulatory and policy differences between LAER and BACT. As discussed in Section 3.0, BACT involves an evaluation of the economic, environmental, and energy impacts of alternative control technologies. In contrast, LAER only considers the technical aspects of control.

More recently, projects with SCR have been installed throughout the US. A majority of these projects are natural gas-fired combined cycle facilities. The size of these projects ranges from 22 MW to over 500 MW. While many of the facilities have distillate oil as backup fuel, distillate oil generally is restricted by permit to 1,000 hours or less per CT.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to over 80 percent of NO_x in the exhaust gas stream. The most common BACT emission limiting standard over the last two years is 3.5 ppmvd corrected to 15-percent O_2 or less for natural gas firing when using DLN and SCR. The most common emission limiting standard established as LAER is 2.5 ppmvd corrected to 15 percent O_2 or less for natural gas firing and using SCR.

Other available control technologies that have become available for controlling NO_x emissions from combustion turbines for include $SCONO_x$™ and XONON™. $SCONO_x$™ is an add-on control using absorption and chemical conversion to remove NO_x formed from combustion, while XONON™ is a catalytic combustion system integral to the turbine. Other potential technologies used in combustion process for NO_x removal include: NO_xOUT, Thermal $DeNO_x$, and NSCR.

Technology Descriptions and Feasibility

Wet Injection

The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion results (i.e., CO and VOC emissions). In "F" Class turbines using wet injection with gas firing, the NO_x emission rates in the range of 30 ppm have been demonstrated. However, wet injection is no longer offered for gas firing in "F" Class turbines. Wet injection is the only current feasible means of reducing NO_x emissions in the combustion process when firing oil.

Dry Low-NO_x Combustor

In the past several years, CT manufacturers have offered and installed machines with dry low-NO_x combustors. These combustors, which are offered on conventional machines manufactured by General Electric (GE), Siemens Westinghouse, Mitsubishi Heavy Industries (MHI) and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. All these vendors have offered dry low-NO_x combustors on advanced heavy-duty industrial machines. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the CT being considered for the project, the combustion chamber design includes the use of dry low-NO_x combustor technology. The NO_x emission level when firing natural gas at baseload conditions is 25 ppmvd (corrected to 15-percent O_2), a level which is guaranteed by the selected vendor for the project.

Selective Catalytic Reduction (SCR)

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

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 = 3N_2 + 6H_2O$$

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined cycle configuration. Exhaust gas temperatures of simple cycle CTs generally are in the range of 1,000°F, which exceeds the optimum range for SCR with base metal catalysts. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been primarily limited to combined-cycle facilities that burn natural gas with small amounts of fuel oil. Initially, the traditional metal catalysts used in SCR systems were contaminated by sulfur-containing fuels. For most fuel-oil-burning facilities, catalyst operation was discontinued, or the exhaust bypasses the SCR system. This was due to the formation of ammonium salts (ammonium sulfate and bisulfate) resulting from the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required with concomitant cost and technical requirements. Ammonium sulfate is emitted as particulate matter. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts. Ceramic and specially designed catalysts have been designed to overcome the problems with base-metal catalysts. The sulfur in No. 2 distillate oil has also been reduced from 0.5 percent available in the early 1990's to 0.05 percent. In addition, HRSG designs can accommodate the impacts of the formation of ammonium salts.

For combined cycle units, SCR is an available, technically feasible and demonstrated technology.

$SCONO_x$™ Process

$SCONO_x$™ is a NO_x and CO control system exclusively offered by Goal Line Environmental Technologies (GLET). GLET is a partnership formed by Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc. In 1998, ABB acquired the exclusive license for the technology in the United States for control applications larger than 100 MW.

The $SCONO_x$™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating.

The $SCONO_x$™ oxidation/absorption cycle reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \qquad (1)$$

$$NO + \frac{1}{2} O_2 \rightarrow NO_2 \qquad (2)$$

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

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:

$$CH_4 + \frac{1}{2} O_2 + 1.88 N_2 \rightarrow CO + 2 H_2 + 1.88 N_2 \quad (5)$$

$$CO + 2 H_2 + H_2O + 1.88 NO_2 \rightarrow CO_2 + 3 H_2 + 1.88 N_2 \quad (6)$$

The SCONO$_x$™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For SCONO$_x$™ systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the SCONO$_x$™ catalyst that reforms the natural gas.

The SCONO$_x$™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system (SCOSO$_x$™) to remove sulfur compounds is installed upstream of the SCONO$_x$™ catalyst. During regeneration of the SCONO$_x$™ catalyst, either hydrogen sulfide or SO_2 is released to the atmosphere as part of the CT/HRSG exhaust gas stream. The absorption portion of the SCOSO$_x$™ process is proprietary. SCOSO$_x$™ oxidation/absorption and regeneration reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (7)$$

$$SO_2 + \frac{1}{2} O_2 \rightarrow SO_3 \quad (8)$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}] \quad (9)$$

$$[SO_3 + \text{SORBER}] + 4 H_2 \rightarrow H_2S + 3 H_2O \quad (10)$$

Utility materials needed for the operation of the SCONO$_x$™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the SCONO$_x$™ control system is limited to one small combined cycle (CC) power plant located in Los Angeles. This power plant, owned by GLET partner Sunlaw Energy Corporation, utilizes a GE LM2500 turbine (30 MW size) equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The SCONO$_x$™ control system was installed at the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 ppmv resulting in an approximate 85 percent NO_x removal efficiency.

A second SCONO$_x$™ system was installed at the Genetics Institute Facility in Andover, Massachusetts in late 1998. The system is installed on a 5-MW Caterpillar Solar Turbine with a Deltak boiler. The NO_x emission limit is 2.5 ppmvd at 15-percent O_2. ABB Environmental reports that the system is operating successfully, although there have been incidents of high NO_x emissions that ABB Environmental attributes to combustion control problems and not to the $SCONO_x$™ system.

XONON™ Catalytic Combustor

Catalytic combustors are being developed for low emission applications on turbines where the catalyst is internal to the combustion system. The XONON™ Combustion System is a catalytic combustion system developed by Catalytica Combustion Systems, Inc. that can achieve low emission levels of NO_x, CO and VOCs. The XONON" system combusts the fuel over a catalyst, reducing the temperature of combustion and providing for more complete combustion of the fuel. The system is referred to as "flameless combustion" where temperatures are below those where limited NO_x formation occurs. However, the exhaust temperatures from a combustion turbine standpoint are still sufficient for the expansion of the gases through the turbine for power generation. Emission levels of NO_x at less than 2 ppm have been reported for the 1.5 MW Kawasaki gas turbine located at Sun Valley Power. Recently, this technology has been proposed for a 750 MW combined cycle facility. This facility, the Pastoria Energy Facility, is a project proposed by affiliates of Enron Corporation, which has a 15 percent interest in Catalytica Combustion Systems, Inc. Commercial operation is scheduled for the summer of 2003. Catalytica is currently working in collaboration with several gas turbine manufacturers including General Electric, Pratt & Whitney, Rolls Royce Allison and Solar.

NO_xOUT Process

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

$$CO(NH_2)_2 + 2NO + \frac{1}{2} O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°F and 1,950°F. Advantages of the system are as follows:

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

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and

2. Sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

Commercial application of the NO_xOUT system is limited and the NO_xOUT system has not been demonstrated on any combustion turbine/HRSG unit.

The NO_xOUT process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the "F" Class CT is about 1,100°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

Thermal DeNO$_x$

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

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

Thus, the Thermal DeNO$_x$ process will not be considered for the proposed project since its high application temperature makes it technically infeasible. The maximum exhaust gas temperature of an "F" Class combustion turbine is typically 1,100°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

Nonselective Catalytic Reduction

Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. CTs have the required temperature but also have high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO$_x$ control device for CTs.

Technology Demonstration and Feasibility

The combustion controls using dry low-NO$_x$ combustors for the combustion turbine and low-NO$_x$ burners for duct firing are available, demonstrated and technically feasible for combustion turbines in either simple cycle or combined cycle configuration. The dry low-NO$_x$ combustion technology alone can achieve 25 ppm (corrected to 15 percent O_2 dry conditions) when firing natural gas.

The technical evaluation of post-combustion gas controls that include NO$_x$OUT, Thermal DeNO$_x$, and NSCR, and indicate that these processes have not been applied to either simple cycle combustion turbines or combined cycle systems and are technically infeasible for the project because of process constraints (e.g., temperature). The SCONO$_x$™ control technology is available but not considered to be technically feasible because it has not been commercially demonstrated on large "F" Class CTs. The CTs planned for the project, Siemens Westinghouse 501F units, each have a nominal generating capacity of 185 MW which are more than seven times larger than the nominal 25-MW GE LM2500 utilized at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the SCONO$_x$™ technology given the large differences in machine flow rates are unknown. Additional concerns with the SCONO$_x$™ control technology include process complexity (multiple catalytic oxidation/absorption/regeneration systems), reliance on only one supplier, relatively brief operating history of the technology, and distillate oil firing. While the XONON" catalytic combustion system is applied directly to the combustion turbine, application on a large combined cycle unit has not been demonstrated. For these reasons, the SCONO$_x$™ and XONON" are still considered in the commercial demonstration stage. SCR is commercially available, technically feasible and demonstrated for combined cycle units.

For combined cycle operation, the combination of dry low-NO$_x$ combustion technology and water injection with SCR is a technically feasible alternative that can achieve a maximum degree of emission reduction. The combined technology is capable of achieving a NO$_x$ emission levels of 3.5 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions), and 12 ppm when firing distillate oil (corrected to 15 percent O_2 dry conditions).

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

	Combined Cycle
Technology	Status
Selective Catalytic Reduction	Available, Demonstrated and Feasible
Dry Low-NO_x Combustors	Available, Demonstrated and Feasible for gas firing
Wet Injection	Available, Demonstrated or Feasible for oil firing
$SCONO_x$	Available, Not Demonstrated
XOXON™	Not Demonstrated
Thermal De NO_x	Not Available or Feasible
NO_x Out	Not Available or Feasible
NSCR	Not Available or Feasible

SCR Cost Estimates

Tables B-3 and B-4 present the total capital and annualized cost to achieve 3.5 ppmvd corrected to 15 percent oxygen when firing natural gas using SCR and $SCONO_x$™ applied to combined cycle operation, respectively. The emission rate for oil firing for both SCR and $SCONO_x$™ is based on 12 ppmvd corrected to 15 percent oxygen. The costs were developed using EPA Cost Control Manual (EPA, 1990 & 1993) and vendor based estimates for each control system. Standard EPA recommended cost factors were used. A capital recovery period of 15 years was used for the capital costs. Tables B-3b and B-4b present the total capital and annualized cost to achieve 2.5 ppmvd corrected to 15 percent oxygen. Tables B-3c and B-4c present the total capital and annualized cost to achieve 2.0 ppmvd corrected to 15 percent oxygen, for $SCONO_x$™ control system.

Comparison of Economic, Environmental, and Energy Impacts

Tables B-5 and B-5b present a comparison of the economic, environmental, and energy impacts associated with the top control alternatives to achieve 3.5 and 2.5 ppmvd corrected to 15 percent oxygen, respectively, when firing gas and 12 ppmvd corrected to 15 percent oxygen when firing oil. Tables B-6 and B-6b, present the potential emissions resulting from the formation of ammonium salts (i.e., particulate matter), ammonia slip and secondary emissions to achieve 3.5 and 2.5 ppmvd corrected to 15 percent oxygen, respectively.

B.2.2 CARBON MONOXIDE

Identification of CO Control Technologies

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. Table B-7 presents a listing of BACT decisions for CO emissions from combustion turbines. Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design.

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

Technology Description

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

Oxidation Catalyst Costs

Tables B-8 and B-9 present the capital and annualized cost for an oxidation catalyst installed in the HRSG.

Comparison of Economic, Environmental, and Energy Impacts

Table B-10 presents a comparison of the economic, environmental, and energy impacts associated with the top control alternatives for the combined cycle unit. Table B-11 presents the potential emissions resulting from the formation of ammonium salts (i.e., particulate matter), ammonia slip and secondary emissions. The latter results from generation lost due to the back pressure of the oxidation catalyst. The maximum CO impacts are less than 0.5 percent of the applicable ambient air quality standards. There would also be no secondary benefits, such as reducing acidic deposition, to reducing CO.

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

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

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

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

Fuel-Bound Nitrogen (percent by weight)	Allowed Increase NO_x Percent by Volume
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

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

Source: 40 CFR 60 Subpart GG.

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1998-2002

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 15 ppm FO	SCR		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	9 ppm or 6 ppm	DLN or SCR		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	6 ppm NG - full load; 42 ppm FO	SCR; WI		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	82.9 lb/hr w/DB, 113.2 lb/hr w/ DB & SA	DLN	30-day	Netting out of PSD for NO_x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Netting out of PSD review for NO_x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr Block	2,800 hr/yr - Power Aug. mode
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	SCR; WI	24-hr Block	SCONOx - \$16,712/ton NO_x.; CatOx - \$2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		SCONOx - no cost eval.; CatOx - \$4,350/ton CO
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	3.5 ppm NG; 16.4 ppm FO	SCR		Repowering project: netting out of NO_x, CO, PM_{10} and SO_2 review (subject to VOC reveiw)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode.
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		base/duct burner/power aug./60-70% load; SCONOx - \$9,982/ton NO_x; CatOx - \$1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	draft permit	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	3.5 ppm NG; 15 ppm FO	SCR		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	3.5 ppm NG; 10 ppm FO	SCR		
Broward Energy Center	FL	draft permit	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	3.5 ppm/9 ppm	SCR/DLN	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 12 ppm FO/25 ppm NG; 42 ppm FO	SCR/DLN; WI		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	draft permit	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Repowering Project: Netting out of PSD for NO_x, SO_2, VOC, lead and SAM (subject for PM_{10} and CO)
FPL Martin	FL	applic. under review	1,150	4	4	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 1,000 FO/1,000; 500 FO	2.5 ppm NG; 12 ppm FO/9-15 ppm NG; 42 ppm FO	SCR/DLN; WI		
FPL Manatee	FL	applic. under review	1,150	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760; 1,000 FO/1,000; 500 FO	2.5 ppm CC/9 ppm SC (15 in HPM)	SCR/DLN		HPM = High Power Mode
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR	30 day	
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Buffalo Creek, LLC	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		SCONOx - \$19,948/ton NO_x; CatOx - \$2,469/ton CO
Augusta Energy LLC	GA	draft permit	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 42 ppm FO	SCR; WI		SCONOx - \$17,490/ton NO_x; CatOx - \$4,133/ton CO

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1998-2002

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
GenPower McIntosh	GA	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Monroe Power Co.	GA	applic. under review	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	12/3.5 ppm	DLN/SCR		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	applic. under review	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	3.5/9 ppm	SCR/DLN;		
Duke Energy Tift	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$16,274/ton NO_x; CatOx - \$2,095/ton CO
CPV Terrapin, LLC	GA	applic. under review	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 5.4 ppm (NG w/DB); 8.0 ppm FO	SCR		
Kinder Morgan Georgia, LLC - Tift Power	GA	applic. under review	560	7	7	1 - GE 7EA & 6 - LM6000	NG	CC	8,760; 3,760 (part load)	9 ppm & 22 ppm	DLN & WI	annual	
Hartwell Development Co.	GA	applic. under review	564	2	0	GE 7FA (176 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$35,422/ton NO_x; CatOx - \$4,964/ton CO
Live Oak Co., LLC	GA	applic. under review	600	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Baldwin County Energy Center	GA	applic. under review	560	2	2	GE 7FA (176 MW)	NG	CC	8,760	3.5 ppm	SCR		
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/NG	CC	8,760	15/20 ppm	Steam Injection	3-hr	
Duke Energy Trimble	KY	applic. under review	1,240	4	4	GE 7FA (160 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm	SCR		
Summer Shade Development Co.	KY	applic. under review	680	4	0	GE 7FA (170 MW)	NG	SC	4,000	9 ppm	DLN		
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		
Cogentrix Energy, Southaven Power Project	MS	draft permit	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	4.5 ppm (10.8 ppm w/ DB)	DLN/SCR		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	3.5 ppm (w/DB)	DLN/SCR		revised application to add SCR
GenPower - McAdams LLC	MS	draft permit	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr	
Lone Oak Energy Center	MS	draft permit	800	3	3	F" Class (180 MW)	NG	CC	8,760	3.5 ppm	SCR		Base/PA/PA+DF/DF
Lee Power Partners	MS	draft permit	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
LSP-Pike Energy LLC	MS	draft permit	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	4.5 ppm	SCR		
Magnolia Energy	MS	draft permit	900	3	3	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	3.5 ppm	DLN, SCR		
Reliant Energy - Choctaw Co., LLC	MS	draft permit	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN, SCR	30-day	SCONOx - \$48,663/ton NO_x; CatOx - \$3,550/ton CO
Crossroads Energy Center	MS	applic. under review	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$23,400/ton NO_x; CatOx - \$11,039/ton CO
Choctaw Gas Generation, LLC	MS	applic. under review	700	2	2	SW 501G (250 MW)	NG	CC	8,760	3.5 ppm	SCR		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	
Granite Power Partners II (Batesville)	MS	applic. under review	300	1	1	SW 501F (230 MW)	NG	CC	8,760	3.5 ppm	SCR		
New Albany Energy Development	MS	applic. under review	566	2	2	GE 7FA (168 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$26,000/ton NOx; CatOx - \$5,100/ton CO
Panada Black Prairie LP	MS	applic. under review	1,040	4	4	F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR		GE7FA or SW501F
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	3.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI	24-hr	Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	draft permit	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Modification of previous permit to switch 2 SC -> CC

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1998-2002

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
GenPower Earleys, LLC	NC	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$21,942/ton NO_x; CatOx - \$3,246ton CO
Mountain Creek - Granville Energy Center	NC	applic. under review	911	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$22,600/ton NOx; CatOx - \$3,560ton CO
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	45 ppm	DLN		Netted out of NO_x, SO_2 and PM_{10} PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	3.5 ppm NG; 12 ppm FO	DLN/SCR; WI		SCONOx - no analysis; CatOx - \$1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	3.5 ppm	DLN/SCR		
Fork Shoals Energy, LLC	SC	applic. under review	1,150	2	2	"F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR		
Cherokee Falls Development Co.	SC	applic. under review	340	2	0	GE 7FA (170 MW)	NG	SC	4,300	9 ppm	DLN		Hot SCR - \$22,800/ton NOx; CatOx - \$10,500/ton CO
GenPower Anderson - revision	SC	applic. under review	340	2	0	GE 7FA (170 MW)	NG	SC	2,928	9 ppm	DLN		Temporary 4 month operating period - *Not Subject to PSD Review for CO, VOC or SO2
Palmetto Energy Center	SC	applic. under review	970	3	3	GE 7FB (180 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - \$18,789/ton NOx; CatOx - \$2,111/ton CO
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	DLN		
Memphis Generation LLC	TN	draft permit	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
Haywood Energy Center (Calpine)	TN	applic. under review	900	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	3.5 ppm NG; 42 ppm FO	DLN/SCR; WI		
TVA - Franklin	TN	applic. under review	610	2	2	GE 7FA (195 MW)		CC	8,760	3.5 ppm	SCR		
REGION 5													
ABB Energy Ventures - Bartlett	IL	Sep-00	558	2	?	2 at 279 MW	NG; FO	CC	8,760	?	SCR	?	
Constellation Power - Holland Energy - Beecher City	IL	Apr-00	336	2	?	168 MW each	NG; FO	CC	8,760	?	SCR		
Peoples Gas, McDonnell Energy	IL	Dec-98	2,500	10	0	250 MW each	NG, ethane	CC	8,760	4.5 ppm	LNC, SCR	1-hr	BACT; Ox Cat rejected at \$3043/ton
LS Power, Kendall Energy	IL	Jun-99	1,000	4	4	250 MW each	NG; FO	CC	8,760	4.5 NG ppm/ 16 FO ppm	DLN, SCR	1-hr	BACT; Ox Cat rejected at \$4083/ton
Reliant Energy (Houston Industries), Cardinal Woods Rivery Refinery	IL	Jul-99	633	3	3	211 MW each	NG, RFG	CC	8760, 1300 hrs with duct burners, more if load < 100%.	3.5 ppm NG; 4.5 ppm RFG	SCR	8 hr/1 hr	BACT & LAER (NOx); Co-located with refinery, separate source; Ox Cat rejected at \$1993/ton
Mid America, Cordova Energy Center	IL	Sep-99	500	2	0	250 MW each	NG	CC	8,760	4.5 ppm	SCR	1-hr	BACT; Ox Cat rejected at \$1307/ton
CILCO - Medinia CoGen - Mossville	IL	May-00	43	3		3 at 14.2 MW each	NG	CC	?	?	DLN		
LS Power, Nelson Project	IL	Jan-00	1,000	4	4	250 MW each	NG; FO	CC	8,760	4.5 ppm NG; 16 ppm FO	SCR	1-hr	BACT; Ox Cat rejected at \$3100/ton
Ameren CIPS	IL	Feb-00	600	2	2	300 MW each	NG	CC	8,760	-	DLN, future SCR	-	BACT for CO and VOC only - netting out of NOx, PM and SO2 review; replacing coal boilers; Ox Cat rejected at \$3400/ton
Holland Energy	IL	draft permit	680	2	2	680 MW	NG; FO	CC	8,760	4.5 ppm NG (3.5 ppm); 16 ppm FO (10 ppm)	SCR	1 hr (24 hr)	BACT; SCR cost \$8,900/ton; Ox Cat rejected at \$10,600/ton
Duke Energy - Kankakee	IL	draft permit	620	2	?	620 MW	NG	CC	8,760				
Duke Energy - Cook County	IL	under review	620	2	?	620 MW	NG	CC	8,760				
Constellation Power Univ. Park	IL	May-00	175	2	?	175 MW	NG; FO	CC	?	?	SCR	?	BACT
Parke County	IN	no appl. (10-99)	?	2		225 MW?	NG; FO	CC	8,760	3.5ppm, ?? FO	DLN and SCR	an/hr	BACT

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1998-2002

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Whiting Clean Energy	IN	applic. under review	?	2		GE 7FA (166 MW)	NG	CC	8,760	3 ppm; 4 ppm w/DB	DLN and SCR		LAER
LSP	IN	applic. under review	?	4		200 MW?	NG; FO	EITHER	8,760	3.5 ppm; 4.5 w/DB, 16 FO	DLN/WI and SCR		BACT
Wyandotte Energy	MI	Feb-99	500	2	2	GE 7FA	NG	CC	8,760	4.5 ppm(33 lb/hr) NG/16 ppm FO	SCR	1 hr	LAER; SCR cost $5600/ton * Time frame required by Michigan Law
Sourthern Energy	MI	Mar-00	1,000	4	4	GE 7FA	NG	CC	8,760	3.5 ppm, 0.013 lb/mm btu	SCR	1 hr	BACT
KM Power Co	MI	Jun-00	550	7	7	1GE 7EA and 6 GE LM 6000	NG	CC	7380 and 4780	9 ppm and 22 ppm	DLN	30 day	BACT
Covert Generating Co	MI	Jan-01	1,200	3	3	Mitsubishi 501 G	NG	CC	8,760	2.5	SCR	24 hr	BACT
Indec Niles Energy Center	MI	application under review	1076	4	4	Siemens V84.3A	NG	CC					
Midland Cogeneration Venture	MI	application under review	510	2	0	ABBK 24-1	NG	CC					
Detroit Edison Co	MI	application under review	250	3		GE PG7121(EA)							
LSP-Cottage Grove	MN	Nov-98	245	1	1	Westinghouse 501F (245 MW)	NG; FO	CC	7,060 NG; 1,700 FO	4.5 ppm NG; 16 ppm FO	SCR	1-hr	BACT
Pleasant Valley	MN	draft permit	444	3		SW V.84.3A & 501D5A (155 MW & 134 MW)	NG; FO		8,760	35 ppm NG; 42 ppm FO	DLN, WI		PSD
Xcel Energy (formerly NSP-Black Dog)	MN	Jan-01	290	1	1	Westinghouse 501F (290 MW)	NG	CC	8760; 1500 hr/yr for duct burners	4.5 ppm	DLN, SCR	3-hr	BACT/PSD
Duke Energy Washington, LLC	OH	Jan-01	340	2	2	GE 7EA (170 MW)	NG	CC	4260 W/O DB; 4500 W/DB	3.5 ppm	SCR	1 hr (ann.)	PSD
PS&G Waterford Energy	OH	-	340	2		GE 7EA (170 MW)		CC		3.5 ppm	SCR		
Dresden Energy	OH	-	340	2		GE 7EA (170 MW)		CC		3.5 ppm	SCR		
Jackson Co. Power	OH	-	640	4		GE 7EA (160 MW)	NG	CC		5 ppm	SCR		

Abbreviations:

GE = General Electric
SW = Seimens Westinghouse

NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner

SC = Simple Cycle
CC = Combined Cycle

DLN = Dry-Low NO_x
WI = Water Injection
SCR = Selective Catalytic Reduction

CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2002)

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1998-2002

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
REGION 3													
Kelson Ridge	MD		1,650	6		Siemens	NG	CC		2.5 ppm	SCR		Major NSR Review
Dickerson Expansion	MD		425	2		GE 7FA	NG	CC		3.5 ppm	SCR		Modification to existing permit (add 2 turbines, repower 2 turbines)
Tenaska	VA		900	3		GE 7FA	NG - Distillate	CC with duct burners	8,760	4.5 ppm or 7 ppm distillate PROPOSED LIMITS - APP	SCR		PSD
Wythe Energy	VA	applic. under review	620	4		GE 7 FA	NG	CC		3.5 ppm	SCR		
Ontelaunee Energy - PA	PA	Oct-00	544	2		Siemens 501F	NG	CC		2.5 ppm	SCR		
AES Ironwood, LLC	PA	Mar-99	700	2			NG; FO	CC	8760 744 (oil)	4.5/10	ALNB, SCR & WI (oil) (LAER)	?	Load restriction 85%
Liberty Electric - Eddystone PA	PA	May-00	500	2	2	GE 7FA	NG/FO	CC	(NG 2117 mscf/12 month rolling) 8760 hours	3.5 ppm CT and 5.0 ppm CT + DB	SCR	1 hour	12 month rolling limit each turbine NOx 113.4 ton CO 253.7 ton VOC 25.1 ton
SWEC - Falls Township, PA	PA		500	2	2	GE 7FA	NG/FO	CC	720 on fuel oil	3 ppm	SCR	1 hour	EPA comment 4/20/01
Lower Mount Bethel PPL	PA	Expected March 2001	600	2	2	Siemens W501F	ng	CC w/DB		3.5 ppm	Dry LNB + SCR		
REGION 4													
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	3.5 ppm NG; 41 ppm w/ FO	DLN/SCR;WI		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.95 ppm NG; 11.3 ppm FO	DLN/SCR; WI/SCR		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		For NO_x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.013/0.048 lb/mmbtu NG/FO - GE; 0.013/0.046 lb/mmbtu NG/FO - Mit	SCR/WI		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu) SC	SCR - CC, DLN-SC	an/1-hr	8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.013 lb/mmBtu (30.7 lb/hr)	SCR	3-hr	
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmBtu)	SCR		
Tenaska Alabama IV Partners	AL	draft permit	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONOx - $6,145/ton NO_x; CatOx- $1,506/ton CO
Duke Energy Autauga, LLC	AL	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $18760/ton NO_x; CatOx- $5,006/ton CO
Duke Energy Dale, LLC	AL	Dec-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmbtu)	SCR		SCONOx - $18,403/ton NOX; CatOx- $2,634/ton CO+VOC

Table B-3. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the S/W 501F Combined Cycle Combustion Turbine
(3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$1,703,362	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$126,865	$0	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725	Vatavauk,1990
Instrumentation	$50,000	$50,000	Additional NO_x Monitor and System
Taxes	$102,202	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$85,168	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$2,112,102	$16,492,225	
Direct Installation Costs			
Foundation and supports	$168,968	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$295,694	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$84,484	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$42,242	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$21,121	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$21,121	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000	Engineering Estimate
Buildings	$15,000	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$653,631	$4,967,668	
Total Capital Costs (TCC)	$2,765,733	$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$211,210	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$105,605	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$211,210	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$42,242	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$21,121	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$63,363	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$704,752	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$3,470,485	$26,572,482	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-3b. Capital Cost for Selective Catalytic Reduction and SCONOx^{TM} for the S/W 501F Combined Cycle Combustion Turbine
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx^{TM}	Basis of Cost Component
<u>Direct Capital Costs</u>			
Pollution Control Equipment	$1,759,493	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$126,865	$0	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725	Vatavauk,1990
Instrumentation	$50,000	$50,000	Additional NO_x Monitor and System
Taxes	$105,570	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$87,975	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$2,174,408	$16,492,225	
<u>Direct Installation Costs</u>			
Foundation and supports	$173,953	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$304,417	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$86,976	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$43,488	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$21,744	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$21,744	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000	Engineering Estimate
Buildings	$15,000	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$672,322	$4,967,668	
Total Capital Costs (TCC)	$2,846,730	$21,459,893	Sum of TDCC, TDIC and RCC
<u>Indirect Costs</u>			
Engineering	$217,441	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$108,720	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$217,441	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$43,488	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$21,744	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$65,232	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$724,066	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$3,570,797	$26,572,482	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-4. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the S/W 501F in Combined Cycle Operation
(3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$18,720	$37,440	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$2,808	$5,616	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$287,461	$0	$300 per ton for Aqueous NH$_3$
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$43,182	$64,773	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times SCR
Catalyst Cost	$393,277	$589,916	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$22,813	$20,932	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$783,262	$718,677	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCONOx
MW Loss and Heat Rate Penalty	$361,962	$670,645	0.32 % output for SCR; 0.6% for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; $3/mmBtu
Natural Gas for SCONOx	$0	$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$389,994	$1,480,029	
Indirect Annual Costs			
Overhead	185,393	25,834	60% of Operating/Supervision Labor and Ammonia
Property Taxes	34,705	265,725	1% of Total Capital Costs
Insurance	34,705	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	381,059	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$635,862	$3,474,942	
Total Annualized Costs	$1,809,118	$5,673,648	Sum of TDAC, TEC and TIAC
Total Cost Effectiveness (25 to 3.5)	$2,741	$8,597	per ton of NO$_x$ Removed
Incremental Cost Effectiveness (25 to 3.5)	$2,741	$8,597	per incremental ton of NO$_x$ Removed
	659.98	659.98	tons NOx removed /year; 3.5 ppmvd corrected to 15% oxygen

Source: Golder 2002. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-4b. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA in Combined Cycle Operation
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$31,200	$62,400	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$4,680	$9,360	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$298,615	$0	$300 per ton for Aqueous NH$_3$
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$45,197	$67,795	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times SCR
Catalyst Cost	$411,628	$617,442	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$24,190	$22,710	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$830,509	$779,707	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCONOx
MW Loss and Heat Rate Penalty	$376,440	$670,645	0.34 % output for SCR; 0.6% for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; $3/n
Natural Gas for SCONOx	$0	$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$404,472	$1,480,029	
Indirect Annual Costs			
Overhead	200,697	43,056	60% of Operating/Supervision Labor and Ammonia
Property Taxes	35,708	265,725	1% of Total Capital Costs
Insurance	35,708	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	392,073	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$664,186	$3,492,164	
Total Annualized Costs	$1,899,167	$5,751,900	Sum of TDAC, TEC and TIAC
Total Cost Effectiveness (25 to 3.0)	$2,770	$8,390	per ton of NO$_x$ Removed
Incremental Cost Effectiveness (3.5 to 2.5)	$3,516	$3,056	per incremental ton of NO$_x$ Removed
	685.59	685.59	tons NOx removed /year; 3.0 ppmvd corrected to 15% oxygen

Source: Golder 2002. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-5. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (3.5 ppmvd corrected)	DLN with SCONOx™ (3.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact[a]			
Capital Costs	included	$3,470,485	$26,572,482
Annualized Costs	included	$1,809,118	$5,673,648
Cost Effectiveness (per ton of Nox removed)			
Total	NA	$2,741	$8,597
Environmental Impact[b]			
Total NOx (TPY)	793	133.4	133.4
NOx Reduction (TPY)	NA	-660	-660
Ammonia Emissions (TPY)	0	113	0
PM Emissions (TPY)	0	9.9	0
Secondary Emissions (TPY)	0	6.7	41.0
Net Emission Reduction (TPY)	NA	-531	-619
Addition Greenhouse Gas (as CO2; tons/year)	0	3,735	22,701
Energy Impacts[c]			
Energy Use (kWh/yr) - Total	0	5,856,360	35,597,336
Energy Use (kWh/yr) - Back Pressure	0	5,155,560	9,552,254
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	488	2,966
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	58,970	358,441
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	59	358
Energy Use (percent of combustion turbine output)	0	0.37%	2.24%

[a] See Tables B-3, B-4, and B-5 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.3 percent of 181 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-5b. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (2.5 ppmvd corrected)	DLN with SCONOx™ (2.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrat	Not Demonstrated
Economic Impact[a]			
Capital Costs	included	$3,570,797	$26,572,482
Annualized Costs	included	$1,899,167	$5,751,900
Cost Effectiveness (per ton of Nox removed)			
Incremental from 2.5 ppm	NA	$3,516	$3,056
Environmental Impact[b]			
Total NOx (TPY)	793	0.0	0.0
NOx Reduction (TPY)	NA	686	686
Ammonia Emissions (TPY)	0	113	0
PM Emissions (TPY)	0	10.1	0
Secondary Emissions (TPY)	0	7.0	41.0
Net Emission Reduction (TPY)	NA	-556	-645
Additional Greenhouse Gas (as CO_2; tons/year)	0	3,866	22,701
Energy Impacts[c]			
Energy Use (kWh/yr)	0	6,062,582	35,597,336
Energy Use (kWh/yr) - Back Pressure	0	5,361,782	9,552,254
Energy Use (kWh/yr) - Other	0	700,800	24,643,482
Energy Use (Equivalent Residential Customers/year)	0	505	2,966
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	61,046	358,441
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	61	358
Energy Use (percent of combustion turbine output)	0	0.38%	2.24%

[a] See Tables B-3b, B-4b, and B-5b for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.34 percent of 181 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOx™

	Incremental Emissions (tons/year) of SCR			Incremental Emissions (tons/year) of SCONOx™		
Pollutants	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	9.86	0.21	10.07		1.30	1.30
Sulfur Dioxide		0.08	0.08		0.49	0.49
Nitrogen Oxides	-659.98	3.93	-656.05	-659.98	23.90	-636.09
Carbon Monoxide		2.36	2.36		14.34	14.34
Volatile Organic Compounds		0.15	0.15		0.94	0.94
Ammonia	112.75					
Total:	-537.38	6.74	-530.64	-659.98	40.96	-619.02
Carbon Dioxide (all energy requirements)		3,734.74	3,734.74		22,701.28	22,701.28

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	58,970	358,441 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-6b. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) (2.0 ppm)

	Incremental Emissions (tons/year) of SCR					
Pollutants	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	9.86	0.22	10.08		1.30	1.30
Sulfur Dioxide		0.08	0.08		0.49	0.49
Nitrogen Oxides	-685.59	4.07	-681.52	-685.59	23.90	-661.69
Carbon Monoxide		2.44	2.44		14.34	14.34
Volatile Organic Compounds		0.16	0.16		0.94	0.94
Ammonia	112.75					
Total:	-562.99	6.98	-556.01	-685.59	40.96	-644.63
Carbon Dioxide (all energy requirements)		3,866.26	3,866.26		22,701.28	22,701.28

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	61,046	358,441 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2002

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.037/0.047/0.069 lb/mmbtu (base/PA/FO) - GE; 0.088/0.116/0.35 lb/mmbtu (base/PA/FO) - Mit	GCP		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	0.023/0.076 lb/mmBtu (w/PA and/or DB)	GCP		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 14 ppm (w/DB)	GCP		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.033 lb/mmBtu (77.7 lb/hr)	GCP		
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	0.035 lb/mmBtu	GCP		
Tenaska Alabama IV Partners	AL	draft permit	1,840	6	6	Mit 501F (170 MW)	NG; FO	CC	8,760; 720 FO	0.088 lb/mmBtu NG (0.115 w/PA & DB); 0.35 lb/mmBtu FO	GCP		SCONOx - $6,145/ton NO_x; CatOx-$1,506/ton CO
Duke Energy Autauga, LLC	AL	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	15 ppm	GCP		SCONOx - $18760/ton NO_x; CatOx-$5,006/ton CO
Duke Energy Dale, LLC	AL	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	0.033 lb/mmbtu	GCP		SCONOx - $18,403/ton NOX; CatOx-$2,634/ton CO+VOC
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	12 ppm, 20 ppm w/ DB NG; 30 ppm FO	GCP		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	12 ppm	GCP		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	6,760; 1,000 FO	12 ppm NG; 20 ppm FO	GCP		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	25 ppm NG - full load; 30 ppm FO	GCP		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	16 ppm w/ DB, 23 ppm w/ DB & SA	GCP		Netting out of PSD for NO_x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	12 ppm NG; 20 ppm FO	GCP		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NO_x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,780	10 ppm (17 ppm w/DB or PA)	GCP	24-hr Block	2,800 hr/yr - Power Aug. mode
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	16 ppm NG; 30 ppm FO	GCP	24-hr Block	SCONOx - $16,712/ton NO_x.; CatOx - $2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		SCONOx - no cost eval.; CatOx - $4,350/ton CO
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	7.2 ppm NG; 14.2 ppm FO	GCP		Repowering project: netting out of NO_x, CO, PM_{10} and SO_2 review (subject to VOC reveiw)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		2 SC CT and 1 CC CT also capable of operating in SC mode.
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	10/15.8/38.5/50 ppm	GCP		base/duct burner/power aug./60-70% load; SCONOx - $9,982/ton NO_x; CatOx - $1,553/ton CO
Jacksonville Electric Authority - Brandy Branch (revision)	FL	draft permit	200	0	2	GE 7FA (170 MW)	NG; FO	CC	8760; 288 FO	12.21/14.17 ppm	GCP		Conversion of 2 SC units to 2 CC units
CPV - Atlantic Power	FL	May-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG (15 ppm w/PA) ; 20 ppm FO	GCP		PA = Power Augmentation
Orlando Utilities - Curtis H Stanton Energy Center	FL	Sep-01	633	2	2	GE 7FA (170 MW)	NG; FO	CC	8,760; 1000 FO	18.1 ppm NG (26.3 w/PA); 14.3 ppm FO	GCP		
Broward Energy Center	FL	draft permit	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	draft permit	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA) ; 17 ppm FO (19 ppm 76-89% load, 26 ppm 50-75% load)	GCP	24-hr	PA limited to 2,000 hr/yr

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2002

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Choctaw Gas Generation, LLC	MS	applic. under review	700	2	2	SW 501G (250 MW)	NG	CC	8,760	23 ppm	GCP		
Duke Energy Homochitto, LLC	MS	applic. under review	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	20.4 ppm	GCP	24-hr	
Granite Power Partners II (Batesville)	MS	applic. under review	300	1	1	SW 501F (230 MW)	NG	CC	8,760	25 ppm	GCP		
New Albany Energy Development	MS	applic. under review	566	2	2	GE 7FA (168 MW)	NG	CC	8,760	13.1 ppm	GCP	annual	SCONOx - $26,000/ton NOx; CatOx - $5.100/ton CO
Panada Black Prairie LP	MS	applic. under review	1,040	4	4	F" Class (175 MW)	NG	CC	8,760	7.6 ppm or 80 ppm	GCP		GE7FA or SW501F
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co. (revision)	NC	draft permit	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	15 ppm NG; 20 ppm FO	GCP		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 41 ppm FO	GCP		
GenPower Earleys, LLC	NC	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (14 ppm w/DB)	GCP		SCONOx - $21,942/ton NO$_x$; CatOx - $3,246ton CO
Mountain Creek - Granville Energy Center	NC	applic. under review	911	3	3	GE 7FA (170 MW)	NG	CC	6,760	9 ppm (24.3 ppm w/DB)	GCP		SCONOx - $22,600/ton NOx; CatOx - $3,560ton CO
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		
SC Electric & Gas - Urquhart	SC	Sep-00	444	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760; 4,380 FO	12 ppm NG; 20 ppm FO	GCP		Netted out of NO$_x$, SO$_2$ and PM$_{10}$ PSD Review
Columbia Energy	SC	Apr-01	515	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	17.4 ppm NG; 37 pm FO	GCP		SCONOx - no analysis; CatOx - $1,611/ton CO
GenPower Anderson	SC	draft permit	640	2	2	GE 7FA (170 MW)	NG	CC	8760	11.7 ppm	GCP		
Fork Shoals Energy, LLC	SC	applic. under review	1,150	2	2	"F" Class (175 MW)	NG	CC	8,760	14 ppm (GE7FA/18 ppm (SW501F)	GCP	24-hr	
Cherokee Falls Development Co.	SC	applic. under review	340	2	0	GE 7FA (170 MW)	NG	SC	4,300	9 ppm	GCP		Hot SCR - $22,800/ton NOx; CatOx - $10,500/ton CO
GenPower Anderson - revision	SC	applic. under review	340	2	0	GE 7FA (170 MW)	NG	SC	2,928	9 ppm*	GCP		Temporary 4 month operating period - Not Subject to PSD Review for CO, VOC or
Palmetto Energy Center	SC	applic. under review	970	3	3	GE 7FB (180 MW)	NG	CC	8,760	15 ppm (31 ppm w/DB)	GCP		SCONOx - $18,789/ton NOx; CatOx - $2,111/ton CO
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	GCP		
Memphis Generation LLC	TN	draft permit	1,050	4	0	GE 7FA (170 MW)	NG	CC	8,760	0.03 lb/mmBtu	GCP		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)
Haywood Energy Center (Calpine)	TN	applic. under review	900	3	3	SW, GE 7FA or GE F7B	NG; FO	CC	8,760	varies from 7.4 to 50 ppm depending on CT type and load	GCP		
TVA - Franklin	TN	applic. under review	610	2	2	GE 7FA (195 MW)		CC	8,760	25 ppm	GCP		
REGION 5													
ABB Energy Ventures - Bartlett	IL	Sep-00	558	2	?	2 at 279 MW	NG; FO	CC	8,760	?			
Constellation Power - Holland Energy - Beecher City	IL	Apr-00	336	2	?	168 MW each	NG; FO	CC	8,760				
Peoples Gas, McDonnell Energy	IL	Dec-98	2,500	10	0	250 MW each	NG, ethane	CC	8,760	15 ppm, 0.031 lb/mmBtu	GCP		BACT; Ox Cat rejected at $3043/ton
LS Power, Kendall Energy	IL	Jun-99	1,000	4	4	250 MW each	NG; FO	CC	8,760	33.1 ppm NG/49.6 ppm FO, 0.0626 w/DB, 0.0511no DB; >75% load	GCP		BACT; Ox Cat rejected at $4083/ton
Reliant Energy (Houston Industries), Cardinal Woods Rivery Refinery	IL	Jul-99	633	3	3	211 MW each	NG, RFG	CC	8760, 1300 hrs with duct burners, more if load < 100%.	0.0472 lb/mmBtu	GCP		BACT & LAER (NOx); Co-located with refinery, separate source; Ox Cat rejected at $1993/ton
Mid America, Cordova Energy Center	IL	Sep-99	500	2	0	250 MW each	NG	CC	8,760	.0547 lb/mmBtu: loads > 75%, after 9/2001	GCP		BACT; Ox Cat rejected at $1307/ton
CILCO - Medinia CoGen - Mossville	IL	May-00	43	3		3 at 14.2 MW each	NG	CC	?				
LS Power, Nelson Project	IL	Jan-00	1,000	4	4	250 MW each	NG; FO	CC	8,760	0.0626 w/DB, 0.0511no DB; >75% load	GCP		BACT; Ox Cat rejected at $3100/ton
Ameren CIPS	IL	Feb-00	600	2	2	300 MW each	NG	CC	8,760	0.06 lb/mmBtu	GCP	3 hr	BACT for CO and VOC only - netting out of NOx, PM and SO2 review; replacing coal boilers; Ox Cat rejected at $3400/ton

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2002

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 10 ppm FO/ 16 ppm NG; 50 ppm FO	GCP		CT will operate in both CC and SC modes
TECO Bayside Power Station	FL	draft permit	1,032	4	0	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (7.8 ppm)	GCP	24-hr (3-hr test)	Repowering Project: Netting out of PSD for NO_x, SO_2, VOC, lead and SAM (subject for PM_{10} and CO)
FPL Martin	FL	applic. under review	1,150	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 1,000 FO/1,000; 500 FO	9-15 ppm NG (29.5 ppm w/DB); 20 ppm FO	GCP		
FPL Manatee	FL	applic. under review	1,150	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760; 1,000 FO/1,000; 500 FO	29.5 ppm CC/9 ppm SC (15 in HPM)	GCP		HPM = High Power Mode
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	6	8	GE 7FA (170 MW)	NG	CC	8,760	29.5 ppm/0.066 lb/MMBtu	GCP		
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	21.8 ppm	GCP		
Duke Energy Buffalo Creek, LLC	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	21.9 ppm	GCP		SCONOx - $19,948/ton NO_x; CatOx - $2,469/ton CO
Augusta Energy LLC	GA	draft permit	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	17.4 ppm NG; 20 ppm FO	GCP		SCONOx - $17,490/ton NO_x; CatOx - $4,133/ton CO
GenPower McIntosh	GA	applic. under review	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm/14 (w/DB) ppm	GCP		
Monroe Power Co.	GA	applic. under review	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	9 ppm	GCP		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	applic. under review	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	10.6 ppm (25 ppm w/DB)	GCP		
Duke Energy Tift	GA	applic. under review	620	2	2	GE 7FA (170 MW)	NG	CC	8,760	24.1 ppm	GCP		SCONOx - $16,274/ton NO_x; CatOx - $2,095/ton CO
CPV Terrapin, LLC	GA	applic. under review	800	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 13.6 ppm (NG w/DB); 24 ppm FO	GCP	24-hr rolling	
Kinder Morgan Georgia, LLC - Tift Power	GA	applic. under review	560	7	7	1 - GE 7EA & 6 LM6000	NG	CC	8,760; 3,760 (part load)	158.5 lb/hr & 141.0 lb/hr	GCP		
Hartwell Development Co.	GA	applic. under review	564	2	0	GE 7FA (176 MW)	NG	CC	8,760	7.4 ppm	GCP		SCONOx - $35,422/ton NO_x; CatOx - $4,964/ton CO
Live Oak Co., LLC	GA	applic. under review	600	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP		
Baldwin County Energy Center	GA	applic. under review	560	2	2	GE 7FA (176 MW)	NG	CC	8,760	9 ppm (24 ppm w/DB)	GCP		
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/ NG	CC	8,760	15/20 ppm	GCP	3-hr	
Duke Energy Trimble	KY	applic. under review	1,240	4	4	GE 7FA (160 MW)	NG; FO	CC	8,760; 1,000 FO	9/13.9/20 ppm	GCP		
Summer Shade Development Co.	KY	applic. under review	660	4	0	GE 7FA (170 MW)	NG	SC	4,000	9 ppm	GCP		
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Duke Energy Attala, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		
Cogentrix Energy, Southaven Power Project	MS	draft permit	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 16 ppm w/ DB	GCP		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	9 ppm	GCP		revised application to add SCR
GenPower - McAdams LLC	MS	draft permit	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	7-8 ppm/13 ppm (w/DB)	GCP	24-hr	
Lone Oak Energy Center	MS	draft permit	600	3	3	F" Class (180 MW)	NG	CC	8,760	10/25/30/17 ppm	GCP		Base/PA/PA+DF/DF
Lee Power Partners	MS	draft permit	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
LSP-Pike Energy LLC	MS	draft permit	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	33.1 ppm (0.15 lb/mmBTU)	GCP		
Magnolia Energy	MS	draft permit	900	3	3	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
Hines Energy Facility	MS	Jan-00	340	2	?	170 MW each	NG	CC	8,760	20 ppm	GCP		
Reliant Energy - Choctaw Co., LLC	MS	draft permit	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	18.38 ppm	GCP		SCONOx - $48,863/ton NO_x; CatOx - $3,550/ton CO
Crossroads Energy Center	MS	applic. under review	560	2	2	GE 7FA (170 MW)	NG	CC	8,760	10.4 ppm	GCP		SCONOx - $23,400/ton NO_x; CatOx - $11,039/ton CO

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2002

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
REGION 3													
Kelson Ridge	MD		1,650	6		Siemens	NG	CC			Cat Ox proposed		Major NSR Review
Perryman Expansion	MD		280				NG	Conversion to CC				Expansion at existing plant	Modification to existing permit
Dickerson Expansion	MD		425	2		GE 7FA	NG	CC					Modification to existing permit (add 2 turbines, repower 2 turbines)
Duke Energy Point of Rocks	MD		620				NG	CC					Major NSR
AES Cumberland	MD		180				Coal	?					Major NSR
Tenaska	VA	]	900	3		GE 7FA	NG - Distillate	CC with duct burners	8,760	21 ppm proposed in application	GCP		PSD
Cogentrix - henry County	VA		1,600	6				CC					PSD Review
Competitive Power Ventures Fluvanna County	VA		530	4				CC					______Cancelled ____
Wythe Energy	VA		620	4	yes	GE 7 FA	NG	CC			State comments Cat OX		
ODEC - Faquier County	VA		500										Synthetic Minor - 249 Tons/Nox
Ontelaunee Energy - PA	PA	Oct-00	544	2		Siemens 501F	NG	CC		10 ppm	GCP		
AES Ironwood, LLC	PA # 32-50109	Mar-99	700	2			NG; FO	CC	8760 744 (oil)	5/10	Entristic high thermodynamic eff.	?	Load restriction 85%
Liberty Electric - Eddystone PA	PA	May-00	500	2	2	GE 7FA	NG/FO	CC	(NG 2117 mscf/12 month rolling) 8760 hours	9ppm CT + 20 ppm CT + DB0	GCP	1 hour	12 month rolling limit each turbine NOx 113.4 ton CO 253.7 ton VOC 25.1 ton
Panda Perkiomen - Montgomery Co., PA	PA	applic. under review	1,000			LM 6000		CC					Strong Public Opposition and Water reuse issues
SWEC - Falls Township, PA	PA		500	2	2	GE 7FA	NG/FO	CC	720 on fuel oil	3 ppm	cat ox	1 hour	EPA comment 4/20/01
FPL - Marcus Hook, PA	PA	applic. under review	750			GE 7FB		CC					
Limerick - Limerick, PA	PA	applic. under review	500					CC					
Connectiv - Lancaster	PA		500										
Connectiv - Delta Project - York County	PA		1,100	6		Siemens V84.2		CC			GCP proposed		
Connectiv - Indiana County	PA		1,000	6		Siemens V84.2		SC and CC					
Sithe	PA		1,600										
Lower Mount Bethel PPL	PA	Expected March 2001	600	2	2	Siemens W501F	ng	CC w/DB		6 PPM	Cat Ox		
Reliant Upper Mount Bethel	PA		580	2	2	Siemens		CC			Cat ox proposed		
Panda	WV		1,000				NG	CC					
Anker	WV		1,000				Coal	CFB					
REGION 4													
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.060 lb/MMBtu	GCP		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	0.040 lb/MMBtu NG; 0.058 lb/mmBtu FO	GCP		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	32.9 ppm NG; 46.7 ppm NG/FO	GCP		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	0.057 lb/MMBtu	GCP		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 19 or 22 ppm	GCP		For NO_x and CO: SC w/GE or SC w/SW501F or CC (either)

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2002

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Holland Energy	IL	draft permit	680	2	2	680 MW	NG; FO	CC	8,760	0.02, 0.04 FO, 0.12 NG w/DB	GCP	1-hr	BACT; SCR cost $8,900/ton; Ox Cat rejected at $10,600/ton
Duke Energy - Kankakee	IL	draft permit	620	2	?	620 MW	NG	CC	8,760				
Duke Energy - Cook County	IL	under review	620	2	?	620 MW	NG	CC	8,760				
Constellation Power Univ. Park	IL	May-00	175	2	?	175 MW	NG; FO	CC	?				BACT
Parke County	IN	no appl. (10-99)	?	2		225 MW?	NG; FO	CC	8,760	unknown			BACT
Whiting Clean Energy	IN	applic. under review	?	2		GE 7FA (166 MW)	NG	CC	8,760	9 ppm; <19 ppm w/duct burners	GCP		LAER
LSP	IN	applic. under review	?	4		200 MW?	NG; FO	EITHER	8,760	33.1 ppm - 234.3 (50% load); 49.6 ppm - 168 ppm (50% load) FO	GCP		BACT
Wyandotte Energy	MI	Feb-99	500	2	2	GE 7FA	NG	CC	8,760	3 ppm (LAER)	Cat Ox	1 hr	LAER; SCR cost $5600/ton * Time frame required by Michigan Law
Sourthern Energy	MI	Mar-00	1,000	4	4	GE 7FA	NG	CC	8,760	0.042 lb/mm btu	GCP	1 hr	BACT
KM Power Co	MI	Jun-00	550	7	7	1GE 7EA and 6 GE LM 6000	NG	CC	7380 and 4780	79 lb/hr and 132 lb/hr	GCP	1 hr	BACT
Covert Generating Co	MI	Jan-01	1,200	3	3	Mitsubishi 501 G	NG	CC	8,760	33.7 lb/hr	Cat Ox	24 hr	BACT
Indec Niles Energy Center	MI	application under review	1076	4	4	Siemens V84.3A	NG	CC					
Midland Cogeneration Venture	MI	application under review	510	2	0	ABBK 24-1	NG	CC					
Detroit Edison Co	MI	application under review	250	3		GE PG7121(EA)							
LSP-Cottage Grove	MN	Nov-98	245	1	1	Westinghouse 501F (245 MW)	NG; FO	CC	7,060 NG; 1,700 FO	1200 lb/hr, 1200 lb/hr FO	Cat Ox	1-hr	BACT
Pleasant Valley	MN	draft permit	444	3		SW V.84.3A & 501D5A (155 MW & 134 MW)	NG; FO		8,760	35 ppm NG; 35 ppm FO	GCP		PSD
Xcel Energy (formerly NSP-Black Dog)	MN	Jan-01	290	1	1	Westinghouse 501F (290 MW)	NG	CC	8760; 1500 hr/yr for duct burners	18 ppm; 25 ppm when duct burners operating; 400 tpy	GCP	3-hr	BACT/PSD
Duke Energy Washington, LLC	OH	Jan-01	340	2	2	GE 7EA (170 MW)	NG	CC	4260 W/O DB; 4500 W/DB	10 ppm w/o DB; 114 w/ DB	GCP	hr/an	PSD
PS&G Waterford Energy	OH	-	340	2		GE 7EA (170 MW)		CC					
Dresden Energy	OH	-	340	2		GE 7EA (170 MW)		CC					
Jackson Co. Power	OH	-	640	4		GE 7EA (160 MW)	NG	CC					

Abbreviations:

GE = General Electric
SW = Seimens Westinghouse

NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner

SC = Simple Cycle
CC = Combined Cycle

DLN = Dry-Low NO_x
WI = Water Injection
SCR = Selective Catalytic Reduction

CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2002)

Table B-8. Direct and Indirect Capital Costs for CO Catalyst, GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$758,000	Vendor Quote
Flue Gas Ductwork	$44,505	Vatavauk,1990
Instrumentation	$75,800	10% of SCR Associated Equipment
Sales Tax	$45,480	6% of SCR Associated Equipment/Catalyst
Freight	$37,900	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$961,685	
Direct Installation Costs		
Foundation and supports	$76,935	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$134,636	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$38,467	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$19,234	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$9,617	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$9,617	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$293,506	
Total Capital Costs	$1,255,191	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$125,519	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$62,760	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$125,519	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$25,104	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$12,552	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$37,656	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$389,109	
Total Direct, Indirect and Capital Costs (TDICC)	$1,644,300	Sum of TCC and TInCC

Table B-9. Annualized Cost for CO Catalyst GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
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	$219,667	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$24,668	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,545	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$259,056	
Energy Costs		
Heat Rate Penalty	$223,548	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$223,548	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$16,443	1% of Total Capital Costs
Insurance	$16,443	1% of Total Capital Costs
Annualized Total Direct Capital	$180,544	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$217,736	
Total Annualized Costs	$700,340	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$3,773	per ton of CO Removed
	$4,070	per ton of Net Emission Reduction

Table B-10. Comparison of Alternative BACT Control Technologies with Installing OC in HRSG

	Alternative BACT Control Technologies	
	DLN Only	DLN with OC
Technical Assessment	Feasible	Available, Feasible and Demonstrated
Economic Impact [a]		
Capital Costs	included	$1,644,300
Annualized Costs	included	$700,340
Cost Effectiveness		
CO Removed (per ton of CO)	NA	$3,773
Environmental Impact [b]		
Total CO (TPY)	216	30
CO Reduction (TPY)	NA	-184
Net Pollutant Reduction	NA	-172
Additional Greenhouse Gas (CO2; tons/yr)	--	2,031
Energy Impacts [c]		
Energy Use (kWh/yr)	0	3,184,085
Energy Use (Equivalent Residential Customers/year)	0	265
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	32,062
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	32

[a] See Tables B-8 and B-9 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-11.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty for 8,760 hours per year. Lost energy is based on 0.2 percent of 166 MW.

Table B-11. Maximum Potential Incremental Emissions (TPY) with Oxidation Catalyst

	Incremental Emissions (tons/year) of SCR		
Pollutants	Primary	Secondary	Total
Particulate	9.86	0.12	9.97
Sulfur Dioxide		0.04	0.04
Nitrogen Oxides	0.00	2.14	2.14
Carbon Monoxide	-185.6	1.28	-184.3
Volatile Organic Compounds		0.08	0.08
Total:	-175.8	3.66	-172.1
Carbon Dioxide (additional from gas firing)		2,030.6	2,030.6

Basis:

Lost Energy (mmBtu/year)	32,062

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

APPENDIX C

APPENDIX C - CALPUFF MODEL DESCRIPTION AND METHODOLOGY

C.1 INTRODUCTION

As part of the new source review requirements under Prevention of Significant Deterioration (PSD) regulations, new sources are required to address air quality impacts at PSD Class I areas. As part of the PSD analysis report submitted to the Florida Department of Environmental Protection (DEP), the air quality impacts due to the potential emissions of the proposed Hines Energy Complex Power Block 3 are required to be addressed at the PSD Class I area of the Chassahowitzka National Wilderness Area (NWA). The Chassahowitzka NWA is located approximately 118 km north-northwest of the facility site and is the only PSD Class I area within 200 km of the facility.

The evaluation of air quality impacts are not only concerned with determining compliance with PSD Class I increments but also assessing a source's impact on Air Quality Related Values (AQRVs), such as regional haze. Further, compliance with PSD Class I increments can be evaluated by determining if the source's impacts are less than the proposed U.S. Environmental Protection Agency (EPA) Class I significant impact levels. The significant impact levels are threshold levels that are used to determine the type of air impact analyses needed for the facility. If the new source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with Class I increments.

Currently there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and Federal Land Managers (FLM) of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources.
These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report.

- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report,* USFS, NPS, USFWS (12/00), referred to as the FLAG document.

For the proposed project, air quality analyses were performed that assess the facility's impacts in the PSD Class I area of the ENP using the refined modeling approach from the IWAQM Phase 2 report for:

- Significant impact analysis
- SO_2 PSD Class I increment analysis; and
- Regional haze analysis

The refined analysis approach was used instead of the screening analysis approach since the air quality impacts are based on generally more realistic assumptions, include more detailed meteorological data, and are estimated at locations at the Class I area.

C.2 GENERAL AIR MODELING APPROACH

The general modeling approach was based on using the long-range transport model, California Puff model (CALPUFF, Version 5.5). At distances beyond 50 km, the ISCST3 model is considered to over-predict air quality impacts, because it is a steady-state model. At those distances, the CALPUFF model is recommended for use. Recently, the FLM have requested that air quality impacts, such as for regional haze, for a source located more than 50 km from a Class I area be predicted using the CALPUFF model. The Florida DEP has also recommended that the CALPUFF model be used to assess if the source has a significant impact at a Class I area located beyond 50 km from the source. As a result, a significant impact and regional haze analyses were performed using the CALPUFF model to assess the facility's impacts at the Chassahowitzka NWA.

The methods and assumptions used in the CALPUFF model were based on the latest recommendations for a refined analysis as presented in the IWAQM Phase 2 Summary Report and the FLAG document.

A regional haze analysis was performed to determine the affect that the facility's emissions will have on background regional haze levels at the Chassahowitzka NWA. In the regional haze analysis, the change in visual range, as calculated by a deciview change, was estimated for the facility in accordance with the IWAQM recommendations. Based on those recommendations, the CALPUFF model is used to predict the maximum 24-hour average sulfate (SO_4), nitrate (NO_3), and fine particulate (PM_{10}) concentrations as well as ammonium sulfate [$(NH_4)_2 SO_4$] and ammonium nitrate (NH_4NO_3) concentrations. The change in visibility due to a source, estimated as a percentage, is then calculated based on the change from background data.

The following sections present the methods and assumptions used to assess the refined significant impact and regional haze analyses performed for the Proposed Project. The results of these analyses are presented in Sections 7.0 and 8.0 of the PSD report.

C.3 MODEL SELECTION AND SETTINGS

The California Puff (CALPUFF, version 5.5) air modeling system was used to model to assess the Proposed Project's impacts at the PSD Class I area for comparison to the PSD Class I significant impact levels and to the regional haze visibility criteria. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALPUFF meteorological and geophysical data preprocessor (CALMET, Version 5.2), a preprocessor to

CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. CALMET was designed to process raw meteorological, terrain and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET was input to CALPUFF to assess the pollutant specific impact. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase 2 and FLAG reports.

C.3.1 CALPUFF MODEL APPROACHES AND SETTINGS

The IWAQM has recommended approaches for performing a Phase 2 refined modeling analyses that are presented in Table 1. These approaches involve use of meteorological data, selection of receptors and dispersion conditions, and processing of model output.

The specific settings used in the CALPUFF model are presented in Table 2.

C.3.2 EMISSION INVENTORY AND BUILDING WAKE EFFECTS

The CALPUFF model included the facility's emission, stack, and operating data as well as building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and were included in the CALPUFF model input. The PSD Analysis Report presents a listing of the facility's emissions and structures included in the analysis.

C.4 RECEPTOR LOCATIONS

For the refined analyses, pollutant concentrations were predicted in an array of 13 discrete receptors located at the Chassahowitzka NWA.

C.5 METEOROLOGICAL DATA

C.5.1 REFINED ANALYSIS

CALMET was used to develop the gridded parameter fields required for the refined modeling analyses. The follow sections discuss the specific data used and processed in the CALMET model.

C.5.2 CALMET SETTINGS

The CALMET settings contained in Table 3 were used for the refined modeling analysis. With the exception of hourly precipitation data files, all input data files needed for CALMET were developed by the FDEP staff.

C.5.3 MODELING DOMAIN

A rectangular modeling domain extending 350 km in the east-west (x) direction and 375 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 27.0 degrees north latitude and 83.5 degrees west longitude. This location is in the Gulf of Mexico approximately 110 km west of Venice, Florida. For the processing of meteorological and geophysical data, the domain contains 70 grid cells in the x-direction and 75 grid cells in the y-direction. The domain grid resolution is 5 km. The air modeling analysis was performed in the UTM coordinate system.

C.5.4 MESOSCALE MODEL – GENERATION 4 (MM4) DATA

Pennsylvania State University in conjunction with the NCAR Assessment Laboratory developed the MM4 data set, a prognostic wind field or "guess" field, for the United States. The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for one database set for the year 1990. The analysis used the MM4 data to initialize the CALMET wind field. The MM4 data have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain.

The MM4 subset domain was provided by FDEP and consisted of a 8 x 7- cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (49,10) to (56,16). These data were processed to create a MM4.DAT file, for input to the CALMET model.

The MM4 data set used in the CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

C.5.5 SURFACE DATA STATIONS AND PROCESSING

The surface station data processed for the CALPUFF analyses consisted of data from six NWS stations or Federal Aviation Administration (FAA) Flight Service stations for Orlando, Fort Myers, Daytona Beach, Vero Beach, Tampa, and Gainesville. A summary of the surface station information and locations are presented in Table 4. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The surface station data were processed into a SURF.DAT file format for CALMET input.

Because the modeling domain extends largely over water, C-Man station data from Venice was obtained. These data were processed by Florida DEP into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. The over-water station data include wind direction, wind speed and air temperature.

C.5.6 UPPER AIR DATA STATIONS AND PROCESSING

The analysis included three upper air NWS stations located in Ruskin, Apalachicola, and West Palm Beach. Data for each station were obtained from the Florida DEP in a format for CALMET input. The data and locations for the upper air stations are presented in Table 4.

C.5.7 PRECIPITATION DATA STATIONS AND PROCESSING

Precipitation data were processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation-recording stations located within the latitude and longitudinal limits of the modeling domain. Data for 27 stations were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were then used to process the data into the format for the PRECIP.DAT file that is used by CALMET. A listing of the precipitation stations used for the modeling analysis is presented in Table 5.

C.5.8 GEOPHYSICAL DATA PROCESSING

Terrain elevations for each grid cell of the modeling domain were obtained from 1-degree Digital Elevation Model (DEM) files obtained from the U.S. Geographical Survey (USGS) internet website. The DEM data was extracted for the modeling domain grid using the utility program TERREL. Land-use data were also extracted from 1-degree USGS files and processed using utility programs CTGCOMP and CTGPROC. Both the terrain and land use files were combined into a GEO.DAT file for input to CALMET with the MAKEGEO utility program.

Table 1. Refined Modeling Analyses Recommendations [a]

Model Input/Output	Description
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; obtain regulatory concurrence on coverage.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition. 3. Define background values for ozone and ammonia for area.
Processing	1. For PSD increments: use highest, second highest 3-hour and 24-hour average SO_2 concentrations; highest, second highest 24-hour average PM_{10} concentrations; and highest annual average SO_2, PM_{10} and NO_x concentrations. 2. For haze: process, on a 24-hour basis, compute the source extinction from the maximum increase in emissions of SO_2, NO_x and PM_{10}; compute the daily relative humidity factor [f(RH)], provided from an external disk file; and compute the maximum percent change in extinction using the FLM supplied background extinction data in the FLAG document. 3. For significant impact analysis: use highest annual and highest short-term averaging time concentrations for SO_2, PM_{10} and NO_x,

[a] IWAQM Phase II report (December, 1998) and FLAG document (December, 2000)

Table 2. CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}
Chemical Transformation	MESOPUFF II scheme, hourly ozone data
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG /MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration file including output species for SO_4, NO_3, PM_{10}, SO_2, and NO_x; process for visibility change using Method 2 and FLAG background extinctions
Model Processing	For haze: highest predicted 24-hour extinction change (%) for the year For deposition: annual average deposition rate For significant impact analysis: highest predicted annual and highest short-term averaging time concentrations for SO_2, NO_x, and PM_{10}.
Background Values	Ozone: 80 ppb; Ammonia: 0.5 ppb

[a] Recommended values by the Florida DEP.

Table 3. CALMET Settings

Parameter	Setting
Horizontal Grid Dimensions	350 by 375 km, 5 km grid resolution
Vertical Grid	9 layers
Weather Station Data Inputs	6 surface, 3 upper air, 27 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 8 x 7 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

Table 4. Surface and Upper Air Stations Used in the CALPUFF Analysis

			UTM Coordinates			
Station Name	Station Symbol	WBAN Number	Easting (km)	Northing (km)	Zone	Anemometer Height (m)
Surface Stations						
Tampa	TPA	12842	349.20	3094.25	17	6.7
Daytona Beach	DAB	12834	495.14	3228.05	17	9.1
Orlando	ORL	12815	468.96	3146.88	17	10.1
Vero Beach	VER	12843	557.52	3058.36	17	6.7
Fort Myers	FMY	12835	413.65	2940.38	17	6.1
Gainesville	GNV	12816	377.40	3284.12	17	6.7
Upper Air Stations						
Ruskin	TBW	12842	349.20	3094.28	17	NA
West Palm Beach	PBI	12844	587.87	2951.42	17	NA
Apalachicola	AQQ	12832	110.00[a]	3296.00	16	NA

[a] Equivalent coordinate for Zone 17.

Table 5. Hourly Precipitation Stations Used in the CALPUFF Analysis

Station Name	Station Number	UTM Coordinate Easting (km)	Northing (km)	Zone
Belle Glade HRCN GT 4	80616	528.190	2953.034	17
Branford	80975	315.606	3315.955	17
Brooksville 7 SSW	81048	358.029	3149.545	17
Canal Point Gate 5	81271	536.428	2971.514	17
Daytona Beach WSO AP	82158	494.165	3227.413	17
Deland 1 SSE	82229	470.780	3209.660	17
Fort Myers FAA/AP	83186	413.992	2940.710	17
Gainesville 11 WNW	83322	355.411	3284.205	17
Inglis 3 E	84273	342.631	3211.652	17
Lakeland	84797	409.871	3099.178	17
Lisbon	85076	423.594	2193.256	17
Lynne	85237	409.255	3230.295	17
Marineland	85391	479.193	3282.030	17
Melbourne	85612	534.381	3109.967	17
Moore Haven Lock 1	85895	491.608	2967.803	17
Orlando WSO McCoy	86628	468.169	3145.102	17
Ortona Lock 2	86657	470.17	2962.27	17
Parrish	86880	366.99	3054.39	17
Port Mayaca S 1 Canal	87293	538.04	2984.44	17
Saint Leo	87851	376.483	3135.086	17
St Lucie New Lock 1	87859	571.04	2999.35	17
St Petersburg	87886	339.61	3071.99	17
Tampa WSCMO AP	88788	348.48	3093.67	17
Venice	89176	357.59	2998.18	17
Venus	89184	467.27	3001.22	17
Vero Beach 4 W	89219	554.27	3056.50	17
West Palm Beach Int AP	89525	589.61	2951.63	17

NOV 1990
TAMPA, FL
NWS CONTRACT MET OBS
P.O. BOX 30100 RM214 HANGER ONE

ISSN 0198-1420

LOCAL CLIMATOLOGICAL DATA

Monthly Summary

INTERNATIONAL AIRPORT

LATITUDE 27° 58'N LONGITUDE 82° 32'W ELEVATION (GROUND) 19 FEET TIME ZONE EASTERN 12842

NOV 1990
TAMPA, FL

DATE 1	TEMPERATURE °F MAXIMUM 2	MINIMUM 3	AVERAGE 4	DEPARTURE FROM NORMAL 5	AVERAGE DEW POINT 6	DEGREE DAYS BASE 65°F HEATING (SEASON BEGINS WITH JUL) 7A	COOLING (SEASON BEGINS WITH JAN) 7B	WEATHER TYPES 1 FOG 2 HEAVY FOG 3 THUNDERSTORM 4 ICE PELLETS 5 HAIL 6 GLAZE 7 DUSTSTORM 8 SMOKE, HAZE 9 BLOWING SNOW 8	SNOW ICE PELLETS OR ICE ON GROUND AT 0700 INCHES 9	PRECIPITATION WATER EQUIVALENT (INCHES) 10	SNOW, ICE PELLETS (INCHES) 11	AVERAGE STATION PRESSURE IN INCHES ELEV. 11 FEET ABOVE M.S.L. 12	WIND (M.P.H.) RESULTANT DIR. 13	RESULTANT SPEED 14	AVERAGE SPEED 15	PEAK GUST SPEED 16	PEAK GUST DIRECTION 17	FASTEST 1-MIN SPEED 18	FASTEST 1-MIN DIRECTION 19	SUNSHINE MINUTES 20	PERCENT OF TOTAL POSSIBLE 21	SKY COVER (TENTHS) SUNRISE TO SUNSET 22	MIDNIGHT TO MIDNIGHT 23
01	84	62	73	3	61	0	8		0	0.00	0.0	30.120	06	8.5	8.7	22	E	15	08	576	87	1	3
02	85	68	77	7	63	0	12		0	0.00	0.0	30.120	07	8.9	9.2	23	E	14	10	562	85	3	4
03	85	64	75	5	62	0	10		0	0.00	0.0	30.100	07	8.3	8.4	18	E	15	08	434	66	3	1
04	88	66	77	8	65	0	12		0	0.00	0.0	29.990	07	7.1	7.2	16	E	12	08	453	69	3	5
05	83	61	72	3	64	0	7		0	0.00	0.0	29.880	27	2.0	5.4	15	W	12	27	538	82	1	1
06	85	61	73	4	68	0	8	1	0	0.03	0.0	29.920	29	3.4	6.4	15	W	13	28	353	54	5	5
07	82	59	71	2	65	0	6	1 8	0	0.00	0.0	30.000	34	2.5	5.9	15	W	12	28	443	68	5	3
08	88*	65	77	9	65	0	12	2 8	0	0.00	0.0	29.980	08	6.9	7.7	18	E	12	08	367	56	4	5
09	85	69	77	9	72	0	12	1 3	0	0.23	0.0	29.860	15	9.1	11.4	28	S	17	12	46	7	9	9
10	76	60	68	0	60	0	3		0	0.00	0.0	29.915	30	14.6	16.0	30	W	22	29	339	52	5	6
11	74	48*	61*	-7	44	4	0		0	0.00	0.0	30.210	04	7.6	8.1	25	N	14	04	620	95	0	0
12	80	50	65	-2	46	0	0		0	0.00	0.0	30.250	01	5.0	5.7	17	NW	14	02	587	90	4	3
13	82	53	68	1	54	0	3		0	0.00	0.0	30.190	02	4.7	5.6	17	E	10	07	461	71	9	7
14	82	59	71	4	57	0	6		0	0.00	0.0	30.250	06	9.5	9.8	21	E	15	06	512	79	3	3
15	83	61	72	5	58	0	7		0	0.00	0.0	30.285	07	8.7	9.0	22	E	15	08	501	78	2	1
16	81	59	70	4	59	0	5		0	0.00	0.0	30.190	06	5.9	6.0	17	E	12	04	375	58	3	4
17	79	57	68	2	57	0	3		0	0.00	0.0	30.050	34	7.8	8.8	24	N	16	33	507	79	1	1
18	76	51	64	-2	46	1	0		0	0.00	0.0	30.070	01	6.9	7.9	17	N	13	36	643	100	1	1
19	76	49	63	-3	49	2	0		0	0.00	0.0	30.130	34	5.2	6.3	13	N	10	31	641	100	1	0
20	77	50	64	-2	51	1	0		0	0.00	0.0	30.165	35	5.5	6.7	15	NW	10	36	584	91	1	1
21	81	54	68	3	53	0	3		0	0.00	0.0	30.170	02	3.9	5.4	14	NW	8	28	495	77	3	2
22	82	55	69	4	59	0	4	2	0	0.00	0.0	30.100	07	3.4	4.5	10	NE	8	05	276	43	6	5
23	78	59	69	4	62	0	4	1 8	0	0.19	0.0	30.010	27	3.4	4.5	14	NW	9	29	420	66	9	8
24	78	63	71	6	67	0	6	1	0	0.14	0.0	30.020	22	2.9	5.0	14	SW	8	27	194	31	9	7
25	81	58	70	5	63	0	5	2 8	0	0.00	0.0	30.130	35	1.5	3.9	13	N	8	01	532	84	3	2
26	85	59	72	8	63	0	7	2 8	0	0.00	0.0	30.160	05	1.6	5.0			10	12	543	86	3	1
27	86	65	76	12	69	0	11	1 3	0	0.05	0.0	30.140	12	4.6	6.5	20	S	13	14	218	34	7	5
28	86	73	80*	16	73	0	15	1	0	0.02	0.0	30.160	12	4.2	7.2	17	SE	12	13	259	41	8	8
29	83	61	72	8	66	0	7	2 8	0	0.00	0.0	30.195	34	3.9	8.9	26	N	16	36	370	59	6	6
30	74	49	62	-2	44	3	0		0	0.00	0.0	30.290	05	12.8	13.6	33	E	24	07	518	82	3	2
	SUM	SUM	—	—	—	TOTAL	TOTAL	NUMBER OF DAYS		TOTAL	TOTAL	FOR THE MONTH:								TOTAL	%	SUM	SUM
	2445	1768	—	—	—	11	176			0.66	0.0	30.100	04	3.4	7.5	33	E	24	07	13367	FOR	121	109
	AVG.	AVG.	AVG.	DEP.	AVG.	DEP.	DEP.	PRECIPITATION		DEP.	—	—	—	—	—	DATE:30		DATE: 30		POSSIBLE	MONTH	AVG.	AVG.
	81.5	58.9	70.2	3.5	59.4	-54	60	≥ .01 INCH.	6	-1.21	—	—	—	—	—					19394	69	4.0	3.6
	NUMBER OF DAYS					SEASON TO DATE		SNOW, ICE PELLETS		GREATEST IN 24 HOURS AND DATES						GREATEST DEPTH ON GROUND OF SNOW, ICE PELLETS OR ICE AND DATE							
						TOTAL	TOTAL	≥ 1.0 INCH	0														
	MAXIMUM TEMP.		MINIMUM TEMP.			18	3938	THUNDERSTORMS	2	PRECIPITATION		SNOW, ICE PELLETS											
	≥ 90°	≤ 32°	≤ 32°	≤ 0°		DEP.	DEP.	HEAVY FOG	5	0.33	23-24	0.0				0							
	0	0	0	0		-47	672	CLEAR 17		PARTLY CLOUDY 8		CLOUDY 5											

* EXTREME FOR THE MONTH - LAST OCCURRENCE IF MORE THAN ONE.
T TRACE AMOUNT.
+ ALSO ON EARLIER DATE(S).
HEAVY FOG: VISIBILITY 1/4 MILE OR LESS.
BLANK ENTRIES DENOTE MISSING OR UNREPORTED DATA.

DATA IN COLS 6 AND 12-15 ARE BASED ON 21 OR MORE OBSERVATIONS AT HOURLY INTERVALS. RESULTANT WIND IS THE VECTOR SUM OF WIND SPEEDS AND DIRECTIONS DIVIDED BY THE NUMBER OF OBSERVATIONS. COLS 16 & 17: PEAK GUST - HIGHEST INSTANTANEOUS WIND SPEED. ONE OF TWO WIND SPEEDS IS GIVEN UNDER COLS 18 & 19: FASTEST MILE - HIGHEST RECORDED SPEED FOR WHICH A MILE OF WIND PASSES STATION (DIRECTION IN COMPASS POINTS). FASTEST OBSERVED ONE MINUTE WIND - HIGHEST ONE MINUTE SPEED (DIRECTION IN TENS OF DEGREES). ERRORS WILL BE CORRECTED IN SUBSEQUENT PUBLICATIONS.

I CERTIFY THAT THIS IS AN OFFICIAL PUBLICATION OF THE NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION, AND IS COMPILED FROM RECORDS ON FILE AT THE NATIONAL CLIMATIC DATA CENTER

Kenneth D Hadeen
DIRECTOR
NATIONAL CLIMATIC DATA CENTER

noaa
NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION
NATIONAL ENVIRONMENTAL SATELLITE, DATA AND INFORMATION SERVICE
NATIONAL CLIMATIC DATA CENTER ASHEVILLE NORTH CAROLINA

OBSERVATIONS AT 3-HOUR INTERVALS

NOV 1990
TAMPA, FL

12842

			VISIBILITY			TEMPERATURE				WIND				VISIBILITY			TEMPERATURE				WIND				VISIBILITY			TEMPERATURE				WIND	
HOUR L.S.T.	SKY COVER (TENTHS)	CEILING IN HUNDREDS OF FEET	WHOLE MILES	16THS MILE	WEATHER	AIR °F	WET BULB °F	DEW POINT °F	REL HUMIDITY %	DIRECTION	SPEED (KNOTS)	SKY COVER (TENTHS)	CEILING IN HUNDREDS OF FEET	WHOLE MILES	16THS MILE	WEATHER	AIR °F	WET BULB °F	DEW POINT °F	REL HUMIDITY %	DIRECTION	SPEED (KNOTS)	SKY COVER (TENTHS)	CEILING IN HUNDREDS OF FEET	WHOLE MILES	16THS MILE	WEATHER	AIR °F	WET BULB °F	DEW POINT °F	REL HUMIDITY %	DIRECTION	SPEED (KNOTS)
					NOV 1st											NOV 2nd											NOV 3rd						
01	2	UNL	12			65	64	63	93	03	5	10	55	15			70	66	64	81	08	5	0	UNL	15			67	64	62	84	06	5
04	0	UNL	10			63	62	62	97	04	5	8	80	15			69	67	65	87	08	5	0	UNL	12			65	63	61	87	05	5
07	0	UNL	10			62	61	60	93	06	4	7	100	15			68	65	63	84	05	7	0	UNL	8			65	64	63	93	04	6
10	1	UNL	15			77	68	62	60	07	8	4	UNL	15			80	71	66	63	07	8	9	70	10			73	67	64	74	07	9
13	1	UNL	15			82	67	58	44	07	9	3	UNL	15			84	70	62	48	08	12	2	UNL	10			83	71	64	53	08	10
16	3	UNL	20			82	67	58	44	07	9	3	UNL	15			84	68	58	41	08	8	1	UNL	15			84	68	58	41	07	10
19	9	70	15			76	66	60	58	07	9	0	UNL	15			76	67	61	60	07	6	0	UNL	15			73	65	60	64	06	5
22	8	75	15			73	66	61	66	06	8	1	UNL	15			72	66	63	73	06	7	0	UNL	15			71	66	63	76	07	6
					NOV 4th											NOV 5th											NOV 6th						
01	0	UNL	15			69	67	66	90	06	8	3	UNL	15			69	65	63	81	07	5	9	60	10			73	72	72	97	18	4
04	8	90	12			68	67	66	93	08	5	2	UNL	15			65	63	62	90	09	3	10	55	10			74	73	72	94	21	5
07	2	UNL	12			66	65	65	97	06	4	3	UNL	12			62	61	61	97	05	3	9	37	12			72	71	71	97	36	3
10	0	UNL	15			80	72	68	67	05	5	0	UNL	10			79	69	63	58	03	4	4	UNL	15			78	74	72	82	24	4
13	4	UNL	15			85	72	65	51	06	8	1	UNL	15			82	69	62	51	26	6	3	UNL	15			83	74	70	65	26	9
16	7	48	15			82	70	64	55	08	10	0	UNL	15			81	69	63	54	27	10	1	UNL	15			81	70	64	56	28	10
19	8	55	15			76	69	65	69	06	5	0	UNL	15			71	68	66	84	28	5	0	UNL	15			69	65	63	81	31	6
22	9	90	15			74	68	64	71	07	4	0	UNL	15			71	70	69	93	21	3	0	UNL	12			64	62	60	87	01	6
					NOV 7th											NOV 8th											NOV 9th						
01	1	UNL	10			60	59	59	97	00	0	0	UNL	8			65	64	64	97	04	3	7	90	12			70	67	65	84	07	6
04	9	4	8			62	61	61	97	08	4	8	6	4		F	66	65	65	97	05	5	9	95	12			71	68	67	87	10	8
07	10	3	2		F	66	65	65	97	07	4	10	0	0	2	F	68	68	68	100	07	5	9	100	10			73	70	68	84	12	10
10	8	7	2		F	72	69	67	84	10	4	0	UNL	6		H	78	72	69	74	10	6	8	100	15			81	75	72	74	14	14
13	2	UNL	6		H	80	73	69	69	25	5	4	UNL	9			86	71	63	46	13	7	10	50	15			84	76	73	70	13	9
16	2	UNL	10			80	71	67	65	28	9	4	UNL	12			83	69	61	48	09	6	10	32	3		RWF	78	77	76	94	18	12
19	0	UNL	10			71	67	65	81	34	7	6	250	12			77	69	65	67	09	9	10	19	7		TRW	79	76	75	88	19	14
22	0	UNL	8			68	67	66	93	01	5	7	80	12			72	67	64	76	06	9	8	250	7			77	76	75	94	21	10
					NOV 10th											NOV 11th											NOV 12th						
01	9	35	7			76	75	74	94	24	8	0	UNL	15			56	52	49	78	03	10	0	UNL	15			54	50	46	75	00	0
04	10	25	7			72	69	67	84	28	18	0	UNL	15			53	50	46	77	03	8	0	UNL	15			51	49	46	83	02	6
07	5	UNL	10			71	64	59	66	29	16	0	UNL	12			48	46	44	86	01	6	2	UNL	15			51	46	41	69	10	3
10	5	UNL	15			75	66	61	62	31	12	0	UNL	12			59	52	46	62	03	9	4	UNL	20			71	57	44	38	01	9
13	6	50	15			72	64	59	64	29	19	1	UNL	12			71	58	46	41	01	9	6	UNL	20			78	59	44	30	01	7
16	3	UNL	15			70	61	55	59	29	17	1	UNL	20			72	55	39	30	07	11	3	UNL	20			79	59	43	28	34	7
19	4	UNL	15			64	59	56	75	31	12	1	UNL	20			62	52	42	48	06	5	2	UNL	20			63	56	51	65	32	4
22	4	UNL	15			62	58	54	75	35	10	0	UNL	20			58	51	44	60	06	3	5	UNL	20			58	56	54	87	35	3
					NOV 13th											NOV 14th											NOV 15th						
01	2	UNL	15			58	57	56	93	00	0	6	UNL	10			61	58	56	84	03	7	0	UNL	15			64	60	57	78	06	7
04	2	UNL	15			56	56	55	97	00	0	3	UNL	10			59	57	55	87	06	6	0	UNL	10			62	60	58	87	07	5
07	7	250	10			53	53	53	100	00	0	5	UNL	10			60	58	56	87	04	6	0	UNL	10			62	60	59	90	06	7
10	8	UNL	15			69	60	53	57	06	4	2	UNL	15			74	65	59	60	08	11	0	UNL	15			76	66	60	58	08	12
13	9	UNL	15			80	64	52	38	06	6	2	UNL	15			80	67	58	47	06	11	3	UNL	15			81	66	57	44	09	11
16	9	UNL	15			79	63	52	39	34	8	2	UNL	15			81	65	55	41	05	10	2	UNL	12			80	67	58	47	05	7
19	8	250	15			66	59	54	65	01	7	1	UNL	15			72	64	58	62	08	9	2	UNL	12			71	62	56	59	07	5
22	10	250	10			65	60	57	76	07	9	0	UNL	15			66	62	59	78	06	6	0	UNL	12			66	62	60	81	06	6
					NOV 16th											NOV 17th											NOV 18th						
01	1	UNL	10			64	62	60	87	07	6	8	80	12			64	61	59	84	35	5	0	UNL	12			56	52	48	75	05	6
04	0	UNL	8			60	59	59	97	06	3	3	UNL	12			62	61	60	93	00	0	0	UNL	12			53	48	43	69	05	6
07	10	70	8			63	61	60	90	05	5	2	UNL	7			62	62	62	100	32	6	0	UNL	12			52	48	43	72	06	5
10	1	UNL	15			75	67	62	64	06	9	0	UNL	15			74	67	62	66	35	9	0	UNL	15			65	55	47	52	36	11
13	4	UNL	15			80	66	57	45	04	7	8	UNL	15			78	63	53	42	34	11	0	UNL	15			74	59	47	38	35	9
16	1	UNL	15			79	65	56	45	07	9	0	UNL	15			75	65	58	56	31	12	3	UNL	20			74	57	42	32	36	9
19	2	UNL	15			68	61	56	66	05	4	0	UNL	15			63	59	55	75	32	6	0	UNL	15			62	53	45	54	36	4
22	3	UNL	15			66	61	58	76	00	0	0	UNL	15			61	54	47	60	03	10	1	UNL	15			59	53	48	67	35	6

WEATHER CODES

*	TORNADO	ZL	FREEZING DRIZZLE	IPW	ICE PELLET SHOWERS	BN	BLOWING SAND
T	THUNDERSTORM	S	SNOW	A	HAIL	BS	BLOWING SNOW
Q	SQUALL	SW	SNOW SHOWERS	F	FOG	BY	BLOWING SPRAY
R	RAIN	SG	SNOW GRAINS	IF	ICE FOG	K	SMOKE
RW	RAIN SHOWERS	SP	SNOW PELLETS	GF	GROUND FOG	H	HAZE
ZR	FREEZING RAIN	IC	ICE CRYSTALS	BD	BLOWING DUST	D	DUST
L	DRIZZLE	IP	ICE PELLETS				

CEILING: UNL INDICATES UNLIMITED
WIND DIRECTION: DIRECTIONS ARE THOSE FROM WHICH THE WIND BLOWS, INDICATED IN TENS OF DEGREES FROM TRUE NORTH: I.E., 09 FOR EAST, 18 FOR SOUTH, 27 FOR WEST. AN ENTRY OF 00 INDICATES CALM
SPEED: THE OBSERVED AVERAGE ONE-MINUTE VALUE, EXPRESSED IN KNOTS (MPH=KNOTS X 1.15).

PAGE 2

OBSERVATIONS AT 3-HOUR INTERVALS

NOV 1990
TAMPA, FL

12842

HOUR L.S.T.	SKY COVER (TENTHS)	CEILING IN HUNDREDS OF FEET	VISIBILITY		WEATHER	TEMPERATURE			REL HUMIDITY %	WIND	
			WHOLE MILES	16THS MILE		AIR °F	WET BULB °F	DEW POINT °F		DIRECTION	SPEED (KNOTS)
					NOV 19th						
01	0	UNL	15			54	51	48	80	01	6
04	0	UNL	15			52	50	48	86	36	6
07	0	UNL	12			49	49	48	96	36	5
10	0	UNL	15			67	58	50	55	36	6
13	1	UNL	15			76	61	49	39	29	6
16	3	UNL	15			73	60	50	45	27	9
19	0	UNL	15			62	55	48	60	33	7
22	0	UNL	15			57	53	49	75	36	3
					NOV 22nd						
01	0	UNL	12			57	55	53	87	06	4
04	0	UNL	9			58	57	57	97	08	5
07	9	75	2	8	F	58	58	58	100	06	4
10	10	70	10			68	64	61	78	05	5
13	1	UNL	15			80	68	60	51	13	5
16	5	UNL	15			80	66	57	45	03	3
19	3	UNL	15			69	64	60	73	06	3
22	6	75	6		F	66	64	63	90	12	3
					NOV 25th						
01	0	UNL	6		F	61	61	61	100	00	0
04	2	UNL	2		F	60	60	60	100	00	0
07	0	UNL	5		F	58	58	58	100	01	3
10	3	UNL	3		F	68	66	64	87	01	6
13	2	UNL	6		H	75	69	66	74	36	4
16	1	UNL	7			79	71	67	67	21	6
19	0	UNL	10			69	67	66	90	27	5
22	0	UNL	8			64	63	63	97	36	3
					NOV 28th						
01	3	UNL	7			73	72	72	97	12	5
04	10	3	1	8	F	73	73	73	100	11	8
07	10	4	1	8	F	74	73	73	97	12	6
10	10	14	7			77	74	73	88	14	9
13	7	UNL	12			85	76	72	65	14	8
16	7	UNL	15			84	75	71	65	28	6
19	9	40	15			79	74	72	79	02	7
22	9	40	8			74	73	73	97	11	4

HOUR L.S.T.	SKY COVER (TENTHS)	CEILING IN HUNDREDS OF FEET	VISIBILITY		WEATHER	TEMPERATURE			REL HUMIDITY %	WIND	
			WHOLE MILES	16THS MILE		AIR °F	WET BULB °F	DEW POINT °F		DIRECTION	SPEED (KNOTS)
					NOV 20th						
01	0	UNL	15			54	50	47	77	01	6
04	0	UNL	15			51	49	47	86	36	4
07	0	UNL	12			51	50	49	93	01	4
10	0	UNL	10			68	58	49	51	36	9
13	0	UNL	14			77	64	55	47	36	4
16	2	UNL	15			75	63	54	48	27	8
19	6	55	15			67	58	50	55	34	7
22	0	UNL	10			62	56	50	65	03	6
					NOV 23rd						
01	10	80	7			65	64	63	93	00	0
04	2	UNL	7			61	60	60	97	00	0
07	3	UNL	2		F	60	60	60	100	00	0
10	10	UNL	5		H	74	68	64	71	27	4
13	10	UNL	12			77	68	62	60	26	5
16	10	80	15			75	62	53	46	29	8
19	10	75	15			71	64	60	68	26	6
22	10	49	9		R	69	67	65	87	27	4
					NOV 26th						
01	0	UNL	7			62	62	62	100	36	4
04	0	UNL	7			60	60	60	100	01	4
07	0	UNL	3		F	60	60	60	100	36	3
10	0	UNL	4		H	76	70	67	74	28	5
13	2	UNL	9			82	69	62	51	34	7
16	4	UNL	15			84	70	63	49	09	5
19	0	UNL	15			73	66	61	66	12	4
22	0	UNL	15			72	68	65	79	10	8
					NOV 29th						
01	8	65	9			75	74	73	94	14	5
04	3	UNL	8			73	72	72	97	13	4
07	9	2	1		F	70	70	70	100	08	3
10	1	UNL	3		H	79	75	73	82	18	3
13	3	UNL	10			83	75	71	67	24	7
16	6	55	12			77	72	70	79	32	11
19	7	55	15			71	67	65	81	35	9
22	8	75	15			67	55	44	44	01	12

HOUR L.S.T.	SKY COVER (TENTHS)	CEILING IN HUNDREDS OF FEET	VISIBILITY		WEATHER	TEMPERATURE			REL HUMIDITY %	WIND	
			WHOLE MILES	16THS MILE		AIR °F	WET BULB °F	DEW POINT °F		DIRECTION	SPEED (KNOTS)
					NOV 21st						
01	0	UNL	12			56	54	52	87	02	4
04	1	UNL	12			55	53	52	90	04	5
07	3	UNL	7			54	53	52	93	05	5
10	3	UNL	9			69	61	56	63	06	6
13	4	UNL	12			80	65	54	41	01	4
16	4	UNL	15			77	64	55	47	28	7
19	3	UNL	15			67	60	54	63	34	5
22	0	UNL	15			61	57	53	75	35	3
					NOV 24th						
01	10	40	3		RF	66	66	66	100	22	4
04	8	55	2		F	66	66	66	100	17	5
07	9	80	3		F	67	66	66	97	15	5
10	10	48	3		RF	69	69	69	100	20	6
13	8	65	20			76	71	69	79	26	5
16	10	55	15			76	71	68	76	26	7
19	2	UNL	10			68	67	66	93	30	5
22	1	UNL	6		GF	64	63	63	97	01	4
					NOV 27th						
01	0	UNL	15			69	67	66	90	12	7
04	0	UNL	6		F	65	64	64	97	09	5
07	2	UNL	5		F	65	64	64	97	08	4
10	10	65	7			75	72	70	85	08	7
13	3	UNL	15			84	75	71	65	13	8
16	5	UNL	15			84	75	71	65	25	6
19	8	33	15			75	73	72	90	19	6
22	8	250	10			73	72	72	97	11	4
					NOV 30th						
01	2	UNL	15			59	49	37	44	36	11
04	5	UNL	15			52	42	27	38	03	12
07	4	UNL	15			49	42	33	54	04	10
10	0	UNL	15			63	54	45	52	05	16
13	0	UNL	15			73	61	51	46	06	15
16	8	UNL	15			70	58	49	47	07	21
19	2	UNL	15			64	57	51	63	08	10
22	2	UNL	15			58	54	51	78	05	5

SUMMARY BY HOURS

HOUR L.S.T	AVERAGES							RESULTANT WIND	
	SKY COVER (TENTHS)	STATION PRESSURE (INCHES)	TEMPERATURE			REL HUMIDITY %	WIND SPEED (MPH)	DIRECTION	SPEED (MPH)
			AIR TEMP °F	WET BULB °F	DEW POINT °F				
01	3	30.100	64	61	59	87	5.6	05	3.4
04	3	30.090	62	60	59	90	5.9	05	3.3
07	4	30.110	61	60	58	91	5.8	05	3.7
10	4	30.145	73	66	61	68	8.8	05	4.8
13	3	30.090	80	68	60	52	9.3	04	2.9
16	4	30.060	79	66	59	52	10.4	35	2.8
19	3	30.090	70	64	59	70	7.5	01	2.8
22	3	30.120	66	62	59	79	6.5	04	4.1

HOURLY PRECIPITATION (WATER EQUIVALENT IN INCHES) NOV 1990 TAMPA, FL 12842

DATE	A.M. HOUR ENDING AT												P.M. HOUR ENDING AT												DATE
	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12	
01																									01
02																									02
03																									03
04																									04
05																									05
06					0.02	0.01																			06
07																									07
08																									08
09														T	0.01	0.10	0.07	0.01	0.01	0.03					09
10																									10
11																									11
12																									12
13																									13
14																									14
15																									15
16																									16
17																									17
18																									18
19																									19
20																									20
21																									21
22																									22
23																						T	0.13	0.06	23
24	0.04	T							T	0.10															24
25																									25
26																									26
27																		T			0.05				27
28																				0.02					28
29																									29
30																									30

MAXIMUM SHORT DURATION PRECIPITATION

TIME PERIOD (MINUTES)	5	10	15	20	30	45	60	80	100	120	150	180
PRECIPITATION (INCHES)	0.07	0.09	0.09	0.12	0.12	0.14	0.16	0.18	0.19	0.19	0.19	0.23
ENDED: DATE	09	09	09	09	23	23	23	23	23	23	23	24
ENDED: TIME	1549	1555	1601	1604	2309	2309	2309	2319	2340	2340	2340	0059

THE PRECIPITATION AMOUNTS FOR THE INDICATED TIME INTERVALS MAY OCCUR AT ANY TIME DURING THE MONTH. THE TIME INDICATED IS THE ENDING TIME OF THE INTERVAL. DATE AND TIME ARE NOT ENTERED FOR TRACE AMOUNTS.

VALIDATED BY:
MATTHEW BODOSKY

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1034 NW 57TH STREET
GAINESVILLE, FL 32605

BUILDING PARAMETER INPUT PROGRAM

(BPIP)

INPUT AND OUTPUT FILES

BPIP INPUT FILE

```
'D:\FPL Hines 3\bpip\hines3.bpv'
'ST'
'Meters' 1.00000000
'UTMN'  0.0000
2
'HRSG3A'  1        0.000
   4       24.000
          -285.280       56.390
          -276.640       56.390
          -276.640       34.000
          -285.280       34.000
'BLDG2'  1        0.000
   4       24.000
          -244.110       56.390
          -235.480       56.390
          -235.480       34.000
          -244.110       34.000
2
'HINES3A'       0.000       38.100      -280.890       29.000
'HINES3B'       0.000       38.100      -239.740       29.000
```

BPIP OUTPUT FILE

```
        BPIP (Dated: 95086)
 DATE : 8/21/ 2
 TIME : 9:35: 8
 D:\FPL Hines 3\bpip\hines3.bpv

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

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

  Inputs entered in Meters    will be converted to meters using
   a conversion factor of   1.0000.  Output will be in meters.

  UTMP is set to UTMN.  The input is assumed to be in a local
   X-Y coordinate system as opposed to a UTM coordinate system.
   True North is in the positive Y direction.

  Plant north is set to   0.00 degrees with respect to True North.

 D:\FPL Hines 3\bpip\hines3.bpv


            PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
                  (Output Units: meters)

                  Stack-Building          Preliminary*
      Stack   Stack   Base Elevation   GEP**   GEP Stack
      Name    Height   Differences     EQN1    Height Value
```

```
HINES3A  38.10   0.00   59.99   65.00
HINES3B  38.10   0.00   60.00   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 : 8/21/ 2

TIME : 9:35: 8

D:\FPL Hines 3\bpip\hines3.bpv

BPIP output is in meters

```
SO BUILDHGT HINES3A  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDHGT HINES3A  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDHGT HINES3A  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDHGT HINES3A  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDHGT HINES3A  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDHGT HINES3A  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDWID HINES3A  12.40  15.78  18.68  21.01  22.71  23.71
SO BUILDWID HINES3A  23.99  23.55  22.39  23.55  23.99  23.71
SO BUILDWID HINES3A  22.71  21.01  18.68  15.78  12.40   8.64
```

```
SO BUILDWID HINES3A  12.40  15.78  18.68  21.01  22.71  23.71
SO BUILDWID HINES3A  23.99  23.55  22.39  23.55  23.99  23.71
SO BUILDWID HINES3A  22.71  21.01  18.68  15.78  12.40   8.64
SO BUILDHGT HINES3B  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDHGT HINES3B  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDHGT HINES3B  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDHGT HINES3B  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDHGT HINES3B  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDHGT HINES3B  24.00  24.00  24.00  24.00  24.00  24.00
SO BUILDWID HINES3B  12.39  15.77  18.67  21.00  22.70  23.71
SO BUILDWID HINES3B  23.99  23.55  22.39  23.55  23.99  23.71
SO BUILDWID HINES3B  22.71  21.00  18.67  15.77  12.39   8.63
SO BUILDWID HINES3B  12.39  15.77  18.67  21.00  22.70  23.71
SO BUILDWID HINES3B  23.99  23.55  22.39  23.55  23.99  23.71
SO BUILDWID HINES3B  22.71  21.00  18.67  15.77  12.39   8.63
```

APPENDIX D

Table D-1. Maximum Pollutant Concentrations Predicted for One Combustion Turbine in Combined Cycle Operation Firing Natural Fuel and Distillate Fuel Oil Based on Modeled Generic Emission Rate

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature									Averaging	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)								
	Base Load			80% Load			60% (NG) /65% Load(FO)				Base Load			80% Load			60% (NG) /65% Load(FO)		
Pollutant	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)	Time	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)
Natural Gas																			
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.1242	0.1350	0.1456	0.1407	0.1494	0.1614	0.1871	0.1963	0.2065
										24-Hour	2.2174	2.4209	2.6103	2.5221	2.6835	2.8574	3.2016	3.3437	3.4683
										8-Hour	4.7269	5.1214	5.4855	5.3163	5.6255	5.9564	6.6051	6.8708	7.1701
										3-Hour	9.3077	10.1234	10.8782	10.5273	11.1687	11.8562	13.2072	13.7613	14.2452
										1-Hour	15.9973	16.9928	17.8914	17.4763	18.2320	19.0268	20.5467	21.1554	21.6804
SO_2	5.6	5.1	4.8	4.3	4.3	4.0	3.8	3.6	3.3	Annual	0.00881	0.00871	0.00876	0.00762	0.00808	0.00808	0.00889	0.00886	0.00857
										24-Hour	0.1573	0.1562	0.1570	0.1367	0.1452	0.1430	0.1520	0.1509	0.1440
										3-Hour	0.660	0.653	0.654	0.571	0.604	0.593	0.627	0.621	0.592
PM10	8.5	7.9	7.2	7.5	7.1	6.3	6.1	5.8	5.5	Annual	0.0132	0.0134	0.0132	0.0133	0.0133	0.0129	0.0143	0.0144	0.0143
										24-Hour	0.2364	0.2396	0.2363	0.2379	0.2396	0.2275	0.2452	0.2460	0.2395
NO_x	25.0	23.1	21.2	20.6	19.1	17.7	16.8	15.9	14.6	Annual	0.039	0.039	0.039	0.037	0.036	0.036	0.040	0.039	0.038
CO	46.0	42.0	37.0	38.0	35.0	33.0	154.0	146.0	134.0	8-Hour	2.74	2.71	2.56	2.55	2.48	2.48	12.82	12.64	12.11
										1-Hour	9.27	8.99	8.34	8.37	8.04	7.91	39.87	38.92	36.61
Distillate Fuel Oil																			
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0704	0.0737	0.0839	0.0712	0.0760	0.0872	0.0795	0.0844	0.0922
										24-Hour	1.5221	1.6108	1.8741	1.5438	1.6693	1.9441	1.7555	1.8879	2.0782
										8-Hour	3.3258	3.5043	4.0286	3.3694	3.6215	4.1668	3.7933	4.0558	4.4300
										3-Hour	6.4214	6.7851	7.8577	6.5102	7.0243	8.1413	7.3757	7.9135	8.6827
										1-Hour	12.0110	12.5090	13.9334	12.1334	12.8322	14.2999	13.3011	14.0058	14.9889
SO_2	105.60	97.13	86.00	85.60	79.36	71.03 #	72.00	68.00	62.00	Annual	0.094	0.090	0.091	0.077	0.076	0.078	0.072	0.072	0.072
										24-Hour	2.03	1.97	2.03	1.67	1.67	1.74	1.59	1.62	1.62
										3-Hour	8.54	8.30	8.51	7.02	7.02	7.29	6.69	6.78	6.78
PM10	64.8	59.6	52.5	52.4	48.6	44.3	43.5	40.9	37.2	Annual	0.0574	0.0554	0.0555	0.0470	0.0465	0.0487	0.0435	0.0435	0.0432
										24-Hour	1.242	1.210	1.240	1.018	1.022	1.086	0.962	0.974	0.974
NO_x	116.9	109.4	96.7	96.6	89.4	80.0	81.2	76.0	69.3	Annual	0.104	0.102	0.102	0.087	0.086	0.088	0.081	0.081	0.081
CO	112.0	106.0	91.0	111.0	103.0	89.0	101.0	94.0	86.0	8-Hour	4.69	4.68	4.62	4.71	4.70	4.67	4.83	4.80	4.80
										1-Hour	16.95	16.71	15.98	16.97	16.65	16.04	16.93	16.59	16.24

Note: NG= natural gas; FO= fuel oil

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1991 to 1995 of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

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 D-2. Maximum Pollutant Concentrations Predicted for Two Combined-Cycle Combustion Turbines Firing Natural Gas and Distillate Fuel Oil by Operating Load and Inlet Ambient Temperature

		Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)								
	Averaging	Base Load			80% Load			60% (NG) /65% Load(FO)		
Pollutant	Time	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)
Natural Gas										
SO_2	Annual	0.018	0.017	0.018	0.015	0.016	0.016	0.018	0.018	0.017
	24-Hour	0.315	0.312	0.314	0.273	0.290	0.286	0.304	0.302	0.288
	3-Hour	1.32	1.31	1.31	1.14	1.21	1.19	1.25	1.24	1.18
PM10	Annual	0.0265	0.0267	0.0264	0.0265	0.0267	0.0257	0.0287	0.0289	0.0285
	24-Hour	0.473	0.479	0.473	0.476	0.479	0.455	0.490	0.492	0.479
NO_x	Annual	0.078	0.079	0.078	0.073	0.072	0.072	0.079	0.079	0.076
CO	8-Hour	5.48	5.42	5.11	5.09	4.96	4.95	25.6	25.3	24.2
	1-Hour	18.5	18.0	16.7	16.7	16.1	15.8	80	78	73
Distillate Fuel Oil										
SO_2	Annual	0.187	0.180	0.182	0.154	0.152	0.156	0.144	0.145	0.144
	24-Hour	4.05	3.94	4.06	3.33	3.34	3.48	3.19	3.24	3.25
	3-Hour	17.1	16.6	17.0	14.0	14.0	14.6	13.4	13.6	13.6
PM10	Annual	0.115	0.111	0.111	0.0940	0.0930	0.0975	0.0871	0.0871	0.0864
	24-Hour	2.48	2.42	2.48	2.04	2.04	2.17	1.92	1.95	1.95
NO_x	Annual	0.21	0.20	0.20	0.17	0.17	0.18	0.16	0.16	0.16
CO	8-Hour	9.39	9.36	9.24	9.42	9.40	9.3	9.7	9.6	9.6
	1-Hour	33.9	33.4	32.0	33.9	33.3	32.1	33.9	33.2	32.5

Note: NG= natural gas; FO= fuel oil

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1991 to 1995 of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

Table D-3. Summary of Maximum Pollutant Concentrations Predicted for Two Combined-Cycle Combustion Turbines Compared to the EPA Class II Significant Impact Levels, PSD Class II Increments, and AAQS

Pollutant	Averaging Time	Maximum Concentration (ug/m3) Natural Gas	 Fuel Oil	 Natural Gas/ Fuel Oil Annual (1)	EPA Class II Significant Impact Levels (ug/m^3)	PSD Class II Increments (ug/m^3)	AAQS (ug/m^3)
SO_2	Annual	0.018	0.19	0.037	1	25	60
	24-Hour	0.31	4.1	NA	5	91	260
	3-Hour	1.3	17.1	NA	25	512	1,300
PM10	Annual	0.029	0.11	0.039	1	17	50
	24-Hour	0.49	2.5	NA	5	30	150
NO_x	Annual	0.079	0.21	0.094	1	25	100
CO	8-Hour	25.6	9.7	NA	500	NA	10,000
	1-Hour	80	33.9	NA	2,000	NA	40,000

NA= not applicable

(1) Based on firing natural gas and fuel oil for the following hours:

Natural gas	7,760 hours
Fuel Oil	1,000 hours
	8,760 hours

10.1.6 Coastal Zone Management Certification

There are no federal licenses, permits or activities required for Power Block 3 that are subject to federal consistency review and affect land or water use. This section is therefore not applicable.

10.2 ZONING DESCRIPTIONS

Zoning was addressed as part of the 1994 Certification preceding; therefore, this section is not applicable. For further information, refer to Section 10.2 of the 1992 SCA.

10.3 LAND USE DESCRIPTION

Land use was addressed as part of the 1994 Certification preceding; therefore, this section is not applicable. For further information, refer to Section 10.3 of the 1992 SCA.

10.4 EXISTING STATE PERMITS OR APPLICATIONS

Per DEP Siting guidelines, this section is not required for supplemental application submissions. State permits or certifications which are applicable to the Hines Energy Complex will be made available upon request.

10.5 MONITORING PROGRAMS

No additional monitoring above that previously conducted, or on going because of the initial certification of the site for full buildout is anticipated to be conducted in conjunction with Power Block 3.