Original

Progress Energy

PSD Application

Hines Energy Complex Power Block 4

Prepared by

Golder Associates

August 2004

Progress Energy

August 5, 2004

RECEIVED
AUG 06 2004
BUREAU OF AIR REGULATION

Mr. Jim Pennington, P.E., Administrator
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Re: **Progress Energy Florida - Hines Energy Complex**
Power Block 4
Supplemental Site Certification Application to PA 92-33
PSD/Air Construction Permit Application

Dear Mr. Pennington:

In conjunction with the filing of the Supplemental Site Certification Application (SSCA) for the addition of the Hines Power Block 4 project to the existing Hines Energy Complex in Polk County, please find enclosed four copies of the PSD/Air Construction permit application for the project. This application package has also been included as Appendix 10.1.5 in the SSCA filed with the Department's Office of Siting Coordination.

All fees associated with the processing of this application have been submitted directly to the Siting Coordination Office, pursuant to 62-17.293(1)(d), F.A.C., for the supplemental certification of a combined cycle facility fueled by natural gas or distillate oil

We look forward to working with you, the Department and other agencies participating in the certification process. Should you, your staff, or any other agency representatives have any questions regarding this application, please do not hesitate to contact me at (813) 826-4363.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

Enclosures

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

BEST AVAILABLE COPY

Golder Associates Inc.

5100 West Lemon Street, Suite 114
Tampa, FL USA 33609
Telephone (813) 287-1717
Fax (813) 287-1716
www.golder.com

REPORT ON

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) AIR PERMIT APPLICATION FOR THE PROPOSED POWER BLOCK 4 AT HINES ENERGY COMPLEX POLK COUNTY, FLORIDA

Submitted to:

Progress Energy Florida
One Power Plaza
263-13th Avenue South
St. Petersburg, Florida 33701-5511

Submitted by:

Golder Associates Inc.
5100 West Lemon Street
Suite 114
Tampa, Florida 33609

Distribution:

10 Copies - Progress Energy Florida
2 Copies - Golder Associates Inc.

August 2004 043-9518

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

ACRONYMS

AQRV	Air quality related values
BACT	Best available control technology
BPIP	Building Parameter Input Program
CAA	Clean Air Act
CALPUFF	California Puff Model
CC	Combined cycle
CEC	Cation exchange capacity
CO	Carbon Monoxide
CT	Combustion turbines
DAT	Deposition analysis thresholds
EPA	U. S. Environmental Protection Agency
FAAQS	Florida Ambient Air Quality Standards
FDEP	Florida Department of Environmental Protection
GEP	Good Engineering Practices
HAP	Hazardous air pollutants
HRSG	Heat recovery steam generators
ISCST3	Industrial Source Complex Short Term dispersion model
IWAQM	Interagency Workgroup on Air Quality Models
MACT	Maximum achievable control technology
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emission Standards for Hazardous Air Pollution
NOx	Nitrogen
NPS	National Park Service
NSPS	New Source Performance Standards
NWA	National Wilderness Area
PEF	Progress Energy Florida
PM	Particulate matter
PSD	Prevention of Significant Deterioration
SCA	Site Certification Application
SCR	Selective catalytic reduction
SCRAM	Support Center for Regulatory Air Models
SO_2	Sulfur Dioxide
STG	Steam turbine generator
TPY	Tons per year
TTN	Technical Transfer Network
VOC	Volatile organic compound

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Progress Energy Florida**	
2. Site Name: **Hines Energy Complex**	
3. Facility Identification Number: **1050234**	
4. Facility Location...: Street Address or Other Locator: **7700 County Road 555** City: **Bartow** County: **Polk** Zip Code: **33830**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Jamie Hunter, Lead Environmental Specialist**
2. Application Contact Mailing Address... Organization/Firm: **Progress Energy Florida** Street Address: **PO Box 14042, MAC BB1A** City: **St. Petersburg** State: **FL** Zip Code: **33733-4042**
3. Application Contact Telephone Numbers... Telephone: **(727) 826-4363** ext. Fax: **(727) 826-4216**
4. Application Contact Email Address:

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	8-6-04
2. Project Number(s):	1050234-010-AC
3. PSD Number (if applicable):	PSD-FL-342
4. Siting Number (if applicable):	PA 92-33

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.
☐ Title V air operation permit revision.
☐ Title V air operation permit renewal.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.
☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Power Block 4 consists of two nominal 170 MW Siemens Westinghouse 501FD combustion turbines (CTs) or equivalent, 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.

Projected or Actual Date of Commencement of Construction: January 2006
Projected Date of Completion of Construction: December 2007

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 PA-92-33SA; PSD-FL-296A. Power Block 3 has permit PA-92-33SA2; PSD-FL-330.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
--	CT - 4A; Power Block 4	AC1A	
--	CT - 4B; Power Block 4	AC1A	

Application Processing Fee

Check one: ☐ Attached - Amount: $________________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **Roger Zirkle, Plant Manager**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Progress Energy Florida** Street Address: **7700 County Road 555** City: **Bartow** State: **FL** Zip Code: **33830**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(863) 519-6103** ext. Fax: **(863) 519-6110**
4.	Owner/Authorized Representative Email Address:
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. 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 and all other requirements identified in this application to which the facility is subject. 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 the facility or any permitted emissions unit.* Roger B Zirkle Signature 8/4/04 Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1.	Application Responsible Official Name:
2.	Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source.
3.	Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4.	Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5.	Application Responsible Official Email Address:
6.	Application Responsible Official Certification: I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. 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 and all other applicable requirements identified in this application to which the Title V source is subject. 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 the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application. ________________ __________ Signature Date

Professional Engineer Certification

1. Professional Engineer Name: **Scott Osbourn**
   Registration Number: **57557**

2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **5100 West Lemon St., Suite 114**
   City: **Tampa** State: **FL** Zip Code: **33609**

3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287-1717** ext.**211** Fax: **(813) 287-1716**

4. Professional Engineer Email Address: **sosbourn@golder.com**

5. 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.

(3) If the purpose of this application is to obtain a Title V 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 plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, 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.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal 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.

Scott Osbourn
Signature

8/4/04
Date

(seal)

SCOTT H. OSBOURN
CERTIFICATE
NO. 57557
STATE OF FLORIDA
PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
**** Board of Professional Engineers Certificate of Authorization #00001670**

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 : **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 Blocks 2 and 3 are each a nominal 530 MW combined-cycle generating unit consisting of 2 CTs, 2 HRSGs, and 1 steam turbine. This application is for the addition of Power Block 4, an additional nominal 530 MW combined-cycle application. See PSD Application.**			

Facility Contact

1. Facility Contact Name: **Roger Zirkle, Plant Manager**
2. Facility Contact Mailing Address... Organization/Firm: **Progress Energy Florida** Street Address: **7700 County Road 555** City: **Bartow** State: **FL** Zip Code: **33830**
3. Facility Contact Telephone Numbers: Telephone: **(863) 519-6103** ext. Fax: **(863) 519-6110**
4. Facility Contact Email Address:

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☐ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **Applicable NSPS is 40 CFR Part 60, Subpart GG.** **62-212.400, F.A.C. See PSD Application.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter - PM	**A**	
Sulfur Dioxide -SO_2	**A**	
Nitrogen Oxides - NO_x	**A**	
Carbon Monoxide - CO	**A**	
Volatile Organic Compounds - VOC	**A**	
Sulfuric Acid Mist - SAM	**B**	

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-1, PSD** ☐ Previously Submitted, Date:____
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-2, PSD** ☐ Previously Submitted, Date:____
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **PSD Applic.** ☐ Previously Submitted, Date:____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **Fig 1-1, PSD** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: ☐ Attached, Document ID:____
3.	Rule Applicability Analysis: ☐ Attached, Document ID:____
4.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:____ ☒ Not Applicable (revision application)	
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:____ ☒ Not Applicable (revision application with no change in applicable requirements)	
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.	
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☒ Not Applicable	
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:____ ☒ Not Applicable	
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:____ ☒ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ 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.

Emissions Unit Description and Status

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

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

   ☐ 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. Description of Emissions Unit Addressed in this Section:
   CT-4A; Power Block 4

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			**49**	☒ Yes ☐ No

9. Package Unit: **Vendor yet to be selected; model will be equivalent to SW 501 FD**
   Manufacturer: **Siemens Westinghouse** Model Number: **501 FD**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
    Siemens Westinghouse 501 FD combustion turbine (or equivalent model) firing natural gas with distillate oil back up.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **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**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **1,915** million Btu/hr	
4. Maximum Incineration Rate:	pounds/hr tons/day
5. Requested Maximum Operating Schedule:	hours/day days/week weeks/year **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input at HHV, 59°F turbine inlet temperature and 100% load; For oil firing, heat input is 2,020 MMBtu/hr (HHV) at 59°F turbine inlet temperature and 100% load; MW nominal rating.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

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: **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 Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 2-1 and 2-2 in PSD application.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **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: **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): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand 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: **BTU based on HHV of 141.2 MMBtu/1,000 gallons. Aggregate fuel usage of 27,360,000 gallons per year requested for Power Block 4, equates to 1,000 hr/CT/yr.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

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			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **64.8** lb/hour **60.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **8.5** lb/hour **34.4** tons/year
5. Method of Compliance: **EPA Method 9; initially and annually.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% opacity**	4. Equivalent Allowable Emissions: **64.8** lb/hour **29.8** tons/year
5. Method of Compliance: **EPA Method 9; when oil firing greater than 400 hr/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

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? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **5.6** lb/hour **22.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **105.6** lb/hour **48.6** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **77.0** lb/hour **126.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Maximum lb/hour based on oil-firing. See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **18.0** lb/hour **78.8** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **77.0** lb/hour **36** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **154** lb/hour **372** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. 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: **EPA Method 10 at 15% O_2**	
6. Allowable Emissions Comment (Description of Operating Method): **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.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **30 ppmvd**	4. Equivalent Allowable Emissions: **112** lb/hour **53** tons/year
5. Method of Compliance: **EPA Method 10; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22** lb/hour **27.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>Allowable Emissions</u> Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.8 ppmvd - baseload/ 3 ppmvd - 60% load**	4. Equivalent Allowable Emissions: **4.7** lb/hour **20** tons/year
5. Method of Compliance: **EPA Method 25A; at 15% O_2**	
6. Allowable Emissions Comment (Description of Operating Method): **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.**	

<u>Allowable Emissions</u> Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd**	4. Equivalent Allowable Emissions: **22** lb/hour **10.5** tons/year
5. Method of Compliance: **EPA Method 25A; at 15% O_2**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

<u>Allowable Emissions</u> Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.2** lb/hour **10.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **10% SO_2** Reference: **Golder, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Emission Factor is converted to SAM. See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **0.9** lb/hour **3.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **16.2** lb/hour **7.44** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. 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: **Gas Firing**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. 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: **Oil Firing**	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. 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: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ 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: **NO_x CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Siemens Westinghouse or equivalent** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **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.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-2** ☐ Previously Submitted, Date ____
2.	Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Tables 2-4/2-5** ☐ Previously Submitted, Date ____
3.	Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Section 4.0** ☐ Previously Submitted, Date ____
4.	Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable (construction application)
5.	Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable
6.	Compliance Demonstration Reports/Records ☐ Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Previously Submitted, Date: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))	
☐ Attached, Document ID: _____	☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)	
☐ Attached, Document ID: _____	☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)	
☒ Attached, Document ID: **See PSD Application**	☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements	
☐ Attached, Document ID: _____	☒ Not Applicable
2. Compliance Assurance Monitoring	
☐ Attached, Document ID: _____	☒ Not Applicable
3. Alternative Methods of Operation	
☐ Attached, Document ID: _____	☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)	
☐ Attached, Document ID: _____	☒ Not Applicable

5. Acid Rain Part Application
   - ☐ Certificate of Representation (EPA Form No. 7610-1)
     - ☐ Copy Attached, Document ID: _____
   - ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
     - ☐ Attached, Document ID: _____
     - ☐ Previously Submitted, Date: _____
   - ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
     - ☐ Attached, Document ID: _____
     - ☐ Previously Submitted, Date: _____
   - ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
     - ☐ Attached, Document ID: _____
     - ☐ Previously Submitted, Date: _____
   - ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
     - ☐ Attached, Document ID: _____
     - ☐ Previously Submitted, Date: _____
   - ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
     - ☐ Attached, Document ID: _____
     - ☐ Previously Submitted, Date: _____
   - ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
     - ☐ Attached, Document ID: _____
     - ☐ Previously Submitted, Date: _____
   - ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT HEC-EU1-C

APPLICABLE REQUIREMENTS LISTING

ATTACHMENT HEC-EU1-C

Applicable Requirements Listing

EMISSION UNIT ID: EU1

FDEP Rules:

Air Pollution Control-General Provisions:

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

Stationary Sources-General:

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

Acid Rain:

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

Stationary Sources-Emission Standards:

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

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

62-297.310(1)	- All Units (Test Runs-Mass Emission)
62-297.310(2)(b)	- All Units (Operating Rate; other than CTs;no CT)
62-297.310(3)	- All Units (Calculation of Emission)
62-297.310(4)(a)	- All Units (Applicable Test Procedures;Sampling time)

62-297.310(4)(b)	- All Units (Sample Volume)
62-297.310(4)(c)	- All Units (Required Flow Rate Range-PM/H2SO4/F)
62-297.310(4)(d)	- All Units (Calibration)
62-297.310(4)(e)	- All Units (EPA Method 5-only)
62-297.310(5)	- All Units (Determination of Process Variables)
62-297.310(6)(a)	- All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	- All Units (Sampling Ports)
62-297.310(6)(d)	- All Units (Work Platforms)
62-297.310(6)(e)	- All Units (Access)
62-297.310(6)(f)	- All Units (Electrical Power)
62-297.310(6)(g)	- All Units (Equipment Support)
62-297.310(7)(a)1.	- Applies mainly to CTs/Diesels
62-297.310(7)(a)2.	- FFSG excess emissions
62-297.310(7)(a)3.	- Permit Renewal Test Required
62-297.310(7)(a)4.a	- Annual Test
62-297.310(7)(a)5.	- PM exemption if <400 hrs/yr
62-297.310(7)(a)6.	- PM FFSG semi annual test required if >200 hrs/yr
62-297.310(7)(a)7.	- PM quarterly monitoring if >100 hrs/yr
62-297.310(7)(a)9.	- FDEP Notification - 15 days
62-297.310(7)(c)	- Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	- Test Reports

Federal Rules:

NSPS Subpart GG:

40 CFR 60.332(a)(1)	- NOx for Electric Utility CTs
40 CFR 60.332(a)(3)	- NOx for Electric Utility CTs
40 CFR 60.333	- SO2 limits
40 CFR 60.334	- Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	- Test Methods

NSPS General Requirements:

40 CFR 60.7(a)(1)	- Notification of Construction
40 CFR 60.7(a)(2)	- Notification of Initial Start-Up
40 CFR 60.7(a)(3)	- Notification of Actual Start-Up
40 CFR 60.7(a)(4)	- Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	- Notification of CEM Demonstration
40 CFR 60.7(b) (startup/shutdown/malfunction)	- Notification and Recordkeeping
40 CFR 60.7(c) (startup/shutdown/malfunction)	- Notification and Recordkeeping

40 CFR 60.7(d) (startup/shutdown/malfunction)	- Notification and Recordkeeping
40 CFR 60.7(f)	- Notification and Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	- Performance Test Requirements
40 CFR 60.8(b)	- Performance Test Notification
40 CFR 60.8(c)	- Performance Tests (representative conditions)
40 CFR 60.8(e)	- Provide Stack Sampling Facilities
40 CFR 60.8(f)	- Test Runs
40 CFR 60.11(a)	- Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	- Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	- Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	- Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	- Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	- Circumvention
40 CFR 60.13(a)	- Monitoring (Appendix B; Appendix F)
40 CFR 60.13(c)	- Monitoring (Opacity COMS)
40 CFR 60.13(d)(1)	- Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(d)(2)	- Monitoring (COMS; span, system check)
40 CFR 60.13(e)	- Monitoring (frequency of operation)
40 CFR 60.13(f)	- Monitoring (frequency of operation)
40 CFR 60.13(h)	- Monitoring (COMS; data requirements)

Acid Rain-Permits:

40 CFR 72.9(a)	- Permit Requirements
40 CFR 72.9(b)	- Monitoring Requirements
40 CFR 72.9(c)(1)	- SO2 Allowances-hold allowances
40 CFR 72.9(c)(2)	- SO2 Allowances-violation
40 CFR 72.9(c)(3)(iii)	- SO2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4)	- SO2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	- SO2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(d)	- NOx Requirements
40 CFR 72.9(e)	- Excess Emission Requirements
40 CFR 72.9(f)	- Recordkeeping and Reporting
40 CFR 72.9(g)	- Liability
40 CFR 72.20(a)	- Designated Representative; required
40 CFR 72.20(b)	- Designated Representative; legally binding
40 CFR 72.20(c)	- Designated Representative; certification requirements
40 CFR 72.21	- Submissions
40 CFR 72.22	- Alternate Designated Representative
40 CFR 72.23	- Changing representatives; owners

40 CFR 72.24	- Certificate of representation
40 CFR 72.30(a)	- Requirements to Apply (operate)
40 CFR 72.30(b)(2)	- Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	- Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	- Requirements to Apply (submittal requirements)
40 CFR 72.31	- Information Requirements; Acid Rain Applications
40 CFR 72.32	- Permit Application Shield
40 CFR 72.33(b)	- Dispatch System ID;unit/system ID
40 CFR 72.33(c)	- Dispatch System ID;ID requirements
40 CFR 72.33(d)	- Dispatch System ID;ID change
40 CFR 72.40(a)	- General; compliance plan
40 CFR 72.40(b)	- General; multi-unit compliance options
40 CFR 72.40(c)	- General; conditional approval
40 CFR 72.40(d)	- General; termination of compliance options
40 CFR 72.51	- Permit Shield
40 CFR 72.90	- Annual Compliance Certification
Allowances:	
40 CFR 73.33(a),(c)	- Authorized account representative
40 CFR 73.35(c)(1)	- Compliance: ID of allowances by serial number
Monitoring Part 75:	
40 CFR 75.4	- Compliance Dates;
40 CFR 75.5	- Prohibitions
40 CFR 75.10(a)(1)	- Primary Measurement; SO2;
40 CFR 75.10(a)(2)	- Primary Measurement; NOx;
40 CFR 75.10(a)(3)(iii)	- Primary Measurement; CO2; O2 monitor
40 CFR 75.10(b)	- Primary Measurement; Performance Requirements
40 CFR 75.10(c)	- Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(e)	- Primary Measurement; Optional Backup Monitor
40 CFR 75.10(f)	- Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	- Primary Measurement; Minimum Recording
40 CFR 75.11(d)	- SO2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	- SO2 Monitoring; Gaseous firing
40 CFR 75.12(a)	- NOx Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(b)	- NOx Monitoring; Determination of NOx emission rate; Appendix F
40 CFR 75.13(b)	- CO2 Monitoring; Appendix G
40 CFR 75.13(c)	- CO2 Monitoring; Appendix F
40 CFR 75.14(c)	- Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	- Initial Certification Approval Process; Loss of Certification

40 CFR 75.20(b)	- Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	- Certification Procedures (if recertification necessary)
40 CFR 75.20(d)	- Recertification Backup/portable monitor
40 CFR 75.20(f)	- Alternate Monitoring system
40 CFR 75.21(a)	- QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	- QA/QC; Calibration Gases
40 CFR 75.21(d)	- QA/QC; Notification of RATA
40 CFR 75.21(e)	- QA/QC; Audits
40 CFR 75.21(f)	- QA/QC; CEMS (Effective 7/17/96-12/31/96)
40 CFR 75.22	- Reference Methods
40 CFR 75.24	- Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	- General Missing Data Procedures; NOx
40 CFR 75.30(a)(4)	- General Missing Data Procedures; SO2
40 CFR 75.30(b)	- General Missing Data Procedures; certified backup monitor
40 CFR 75.30(c)	- General Missing Data Procedures; certified backup monitor
40 CFR 75.30(d)	- General Missing Data Procedures; SO2 (optional before 1/1/97)
40 CFR 75.30(e)	- General Missing Data Procedures; bypass/multiple stacks
40 CFR 75.31	- Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	- Monitoring Data Availability for Missing Data
40 CFR 75.33	- Standard Missing Data Procedures
40 CFR 75.36	- Missing Data for Heat Input
40 CFR 75.40	- Alternate Monitoring Systems-General
40 CFR 75.41	- Alternate Monitoring Systems-Precision Criteria
40 CFR 75.42	- Alternate Monitoring Systems-Reliability Criteria
40 CFR 75.43	- Alternate Monitoring Systems-Accessability Criteria
40 CFR 75.44	- Alternate Monitoring Systems-Timeliness Criteria
40 CFR 75.45	- Alternate Monitoring Systems-Daily QA
40 CFR 75.46	- Alternate Monitoring Systems-Missing data
40 CFR 75.47	- Alternate Monitoring Systems-Criteria for Class
40 CFR 75.48	- Alternate Monitoring Systems-Petition
40 CFR 75.53	- Monitoring Plan ; revisions
40 CFR 75.54(a)	- Recordkeeping-general
40 CFR 75.54(b)	- Recordkeeping-operating parameter
40 CFR 75.54(c)	- Recordkeeping-SO2
40 CFR 75.54(d)	- Recordkeeping-NOx
40 CFR 75.54(e)	- Recordkeeping-CO2
40 CFR 75.54(f)	- Recordkeeping-Opacity
40 CFR 75.55(c)	- General Recordkeeping (Specific Situations)

40 CFR 75.55(e)	- General Recordkeeping (Specific Situations)
40 CFR 75.56	- Certification; QA/QC Provisions
40 CFR 75.60	- Reporting Requirements-General
40 CFR 75.61	- Reporting Requirements-Notification
cert/recertification	
40 CFR 75.62	- Reporting Requirements-Monitoring Plan
40 CFR 75.63	- Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	- Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	- Reporting Requirements-Quarterly reports; DR
statement	
40 CFR 75.64(c)	- Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	- Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.66	- Petitions to the Administrator (if required)
Appendix A-1	- Installation and Measurement Locations
Appendix A-2.	- Equipment Specifications
Appendix A-3.	- Performance Specifications
Appendix A-4.	- Data Handling and Acquisition Systems
Appendix A-5.	- Calibration Gases
Appendix A-6.	- Certification Tests and Procedures
Appendix A-7.	- Calculations
Appendix B	- QA/QC Procedures
Appendix C-1.	- Missing Data; SO2/NOx for controlled sources
Appendix C-2.	- Missing Data; Load-Based Procedure; NOx & flow
Appendix D	- Optional SO2; Oil-/gas-fired units
Appendix F	- Conversion Procedures
Appendix H	- Traceability Protocol

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

40 CFR 77.3	- Offset Plans (future)
40 CFR 77.5(b)	- Deductions of Allowances (future)
40 CFR 77.6	- Excess Emissions Penalties (SO2 and NOx;future)

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ 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.

Emissions Unit Description and Status

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

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

   ☐ 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. Description of Emissions Unit Addressed in this Section:
   CT-4B; Power Block 4

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			**49**	☒ Yes ☐ No

9. Package Unit: **Vendor yet to be selected; model will be equivalent to SW 501 FD**
   Manufacturer: **Siemens Westinghouse** Model Number: **501 FD**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
    Siemens Westinghouse 501 FD combustion turbine (or equivalent model) firing natural gas with distillate oil back up.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **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**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **1,915** million Btu/hr	
4. Maximum Incineration Rate:	pounds/hr tons/day
5. Requested Maximum Operating Schedule:	hours/day days/week weeks/year **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input at HHV, 59°F turbine inlet temperature and 100% load; For oil firing, heat input is 2,020 MMBtu/hr (HHV) at 59°F turbine inlet temperature and 100% load; MW nominal rating.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

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: **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 Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 2-1 and 2-2 in PSD application.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **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: **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): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand 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: **BTU based on HHV of 141.2 MMBtu/1,000 gallons. Aggregate fuel usage of 27,360,000 gallons per year requested for Power Block 4, equates to 1,000 hr/CT/yr.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	026	065	EL
CO			EL
VOC			EL
SAM			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **64.8** lb/hour **60.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **8.5** lb/hour **34.4** tons/year
5. Method of Compliance: **EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% opacity**	4. Equivalent Allowable Emissions: **64.8** lb/hour **29.8** tons/year
5. Method of Compliance: **EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

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? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **5.6** lb/hour **22.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **105.6** lb/hour **48.6** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **77.0** lb/hour **126.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Maximum lb/hr based on oil-firing. See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **18.0** lb/hour **78.8** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **77.0** lb/hour **36** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **154** lb/hour **372** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. 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: **EPA Method 10 at 15% O_2**	
6. Allowable Emissions Comment (Description of Operating Method): **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.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **30 ppmvd**	4. Equivalent Allowable Emissions: **112** lb/hour **53** tons/year
5. Method of Compliance: **EPA Method 10; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22** lb/hour **28.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.8 ppmvd - baseload/ 3 ppmvd - 60% load**	4. Equivalent Allowable Emissions: **4.7** lb/hour **20** tons/year
5. Method of Compliance: **EPA Method 25A; at 15% O_2**	
6. Allowable Emissions Comment (Description of Operating Method): **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.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd**	4. Equivalent Allowable Emissions: **22** lb/hour **10.5** tons/year
5. Method of Compliance: **EPA Method 25A; at 15% O_2**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.2** lb/hour **10.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **10% SO_2** Reference: **Golder, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Emission Factor is converted to SAM. See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas**	4. Equivalent Allowable Emissions: **0.9** lb/hour **3.4** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **16.2** lb/hour **7.44** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor or Applicant**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. 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: **Gas Firing**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. 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: **Oil Firing**	

EMISSIONS UNIT INFORMATION
Section [2] of [2]
CT-4B; Power Block 4

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. 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: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ 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: **NO_x CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Siemens Westinghouse or equivalent** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **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.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Fig 2-2** ☐ Previously Submitted, Date ____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Tables 2-4/2-5** ☐ Previously Submitted, Date ____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Section 4.0** ☐ Previously Submitted, Date ____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☒ Attached, Document ID: **See PSD Application** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: See PSD Application ☐ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ____ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☒ Not Applicable	

Additional Requirements Comment

1.0 INTRODUCTION

Progress Energy Florida (PEF) 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 are Power Block 1, consisting of one 485 MW (nominal 500 MW) combined cycle (CC) power generation unit and Power Block 2, consisting of one 530 MW CC power generation unit. Power Block 3, which is identical to Power Block 2, consists of 530 MW of CC power generation 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 PEF maximum flexibility and cost control as both technology and electrical demand increases.

Power Block 4 (the Project) will consist of two nominal 170 MW Siemens Westinghouse 501 FD combustion turbines (CTs) or their equivalent, 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 4 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 51.166), 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 4. As a result, Power Block 4 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 4, it has been prepared as a stand-alone PSD permit application. The permit application is divided into nine 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.

2.0 PROJECT DESCRIPTION

2.1 General Description

The proposed Power Block 4 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 is 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) and water injection to limit emissions of oxides of nitrogen (NO_X), and good combustion practices and clean fuels for the minimization of particulate matter (PM/PM10), 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 4 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 4, inclusive of potential inlet cooling.

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 SO2, PM/PM10, NOX, 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).

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

For formaldehyde, a review of EPA's database was conducted and an emission factor was estimated based on comparisons of the turbines and emission characteristics from EPA's database to those proposed for this project. A discussion regarding this review and estimation of the formaldehyde emission factor is presented in the following paragraphs.

The recent EPA emission factor suggests formaldehyde emissions from gas turbines of 710 lb/10^{12} Btu when firing natural gas at loads greater than 80 percent and 280 lb/10^{12} Btu when firing distillate oil. The EPA suggested emission factor for all loads is 3,100 lb/10^{12} Btu. Since the proposed CTs will fire primarily natural gas, with limited oil firing, the worst-case annual emissions would be from natural gas firing. The emission factors are not appropriate for the proposed CTs based on several factors. First, and most importantly, the data used to develop the AP-42 emission factors are not representative of the large frame combustion turbines. Second, a review of the data of the pertinent information in the EPA database that relates to the characteristics clearly suggests a much lower emission factor for formaldehyde. Some of the important aspects of the EPA Gas Turbine Database related to formaldehyde emissions are as follows.

- The formaldehyde emissions are from small (< 30 MW) gas turbines. The available data are from an average capacity of about 28 MW. More importantly, the median capacity, or the turbine size where an equal number of turbines are above and below that size, is about 15 MW. Data from only 8 large turbines (>30 MW) are included in the EPA database, with a maximum size of 88 MW.

- In contrast to the AP-42 emission factors for formaldehyde, which are based on an average value, the median value is substantially lower. For all loads, the median formaldehyde emission factor is about 320 $lb/10^{12}$ Btu; for turbine loads greater than 50 percent, the median emission factor is about 110 $lb/10^{12}$ Btu. Since the median emission factor is about 8 to ten times lower than the average factor, this clearly points to the large range in formaldehyde emissions and how the individual turbine combustion characteristics can influence the results. The median is a measure of the middle of the distribution and in distributions where there is symmetry about the mean, and where the mean and median coincide. However, in highly skewed distributions, as that observed for formaldehyde emissions, the median is more representative of a "truer average" since the median is not influenced by extreme values.

- There is a strong relationship between formaldehyde and CO emissions, as noted by EPA in the support document and, and as observed in the data. Gas turbines with higher CO emissions had higher observed formaldehyde emissions. An evaluation of the coincident CO and formaldehyde data indicates that formaldehyde emissions were 150 $lb/10^{12}$ Btu when the CO emissions are less than 0.1 lb/MMBtu.

At present, there are no confirmed test data of formaldehyde emissions from similar Siemens Westinghouse or equivalent combustion turbines.

Based on the available data, formaldehyde emissions would be within the range of 100 to 150 $lb/10^{12}$ Btu. The applicable combustion turbine MACT standard (40 CFR 63, Subpart YYYY) limits emissions of formaldehyde to 91 parts per billion (ppb) by volume, corrected to 15 percent oxygen. For the proposed power equipment, this emission rate is equivalent to 204 and 214 $lb/10^{12}$ BTU (gas and oil-firing, respectively at 59F). Based on available data, it appears that the proposed Power Block 4 will meet the maximum achievable control technology (MACT) limits. A more detailed discussion of Subpart YYYY applicability is presented in Section 3.3.4.

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 4 of 27,360,000 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 4 as well as existing Power Blocks 1, 2 and 3 is depicted in Figure 2-1. This configuration arrangement includes the existing 485 MW Power Block 1, the 530 MW Power Blocks 2 and 3, as well as the proposed 530 MW Power Block 4. Each power block consists of two CTs, two HRSGs, and one steam turbine. The eight HRSG stacks are arranged in an east-west line. The flow diagram for a single power block 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

<u>CONDITIONS</u>			
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	1,915	1,705
<u>EMISSIONS</u> (lb/hr)			
Carbon Monoxide (10 ppmvd at 15% O_2)	46	42	37
Nitrogen Oxides (2.5 ppmvd at 15% O_2)[3]	18.0	16.5	15.1
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	4.2
Lead	Neg.	Neg.	Neg.
Sulfuric Acid Mist	0.9	0.8	0.7
<u>STACK PARAMETERS</u>			
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	2,020	1,707
EMISSIONS (lb/hr)			
Carbon Monoxide (30 ppmvd at 15% O_2)	112	106	91
Nitrogen Oxides (10 ppmvd at 15% O_2)	77.0	73.0	64.4
Sulfur Dioxide	105.6	97.1	85.8
Particulate Matter (PM_{10})	64.8	59.6	52.5
Opacity (%)	20	20	20
VOCs (10 ppmvd at 15% O_2)	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	201	40	Yes
Sulfur Dioxide	137	40	Yes
Particulate Matter (PM_{10})	121	15	Yes
Total Suspended Particulates Volatile	121	25	Yes
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 4 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)	130 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: PEF, 2004

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 4. 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 SO2 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, PM10, 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 SO2 and PM10 concentrations, or before February 8, 1988, for NO2 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 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. he 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 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 4 CC units are subject to NSPS Subpart GG. 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 4 (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 NOx and SO2. The NOx emission limitation is set by the following equation:

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

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 SO2 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 emission monitoring systems, low water-to-fuel ratio, and fuel sulfur content greater than 0.8% by weight. The reporting requirement includes submittal of the quarterly 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.

3.3.3.2 Combined Cycle Units

The FDEP has not adopted any state-specific emission standards in rule 62-296, F.A.C. relating to the operation of a CC unit. The FDEP has adopted the NSPS requirements of Subparts A and GG by reference in rule 62-204.800, F.A.C. Based on the current FDEP rules; the CC units must meet the NSPS requirements as discussed in Section 3.3.2.2. In addition, a general opacity limit of less than 20 percent and a prohibition on emitting air pollutants that cause or contribute to an objectionable odor apply.

3.3.3.3 Excess Emissions

The FDEP has adopted standards relating to excess emissions in rule 62-210.700, F.A.C. The rule allows excess emissions resulting from startup, shutdown, or malfunction of any source as long as best operational practices are applied and the excess emissions do not exceed 2 hours in any 24-hour period. Currently, the rule allows one exception from the 2-hour limit and that is for existing fossil fuel steam generators. The FDEP can authorize different excess emission parameters for other sources on a case-by-case basis.

Based on the intended operation of the CC units, it is requested that the FDEP consider the operational variations of this equipment as well as the EPA's NSPS requirements on excess emissions and set an allowable excess emissions level for Power Block 4 as follows:

> *"Excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed 120 minutes in a 24-hour calendar day block period except for the following specific cases.*
>
> *a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed 6 hours in any 24-hour calendar day block period. A cold "startup of the steam turbine system" is defined as startup of the 2-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. On days in which a cold startup occurs, a total of up to eight hours of combined excess emissions are allowed.*

{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue.}

b. For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed 3 hours in any 24-hour period. On days in which a shutdown occurs, a total of up to 5 hours of combined excess emissions are allowed.

3.3.4 NESHAPS

EPA released a signed final rule promulgating the MACT standard for combustion turbines (40 CFR 63, Subpart YYYY) on March 5, 2004. According to the final rule, each of these new units would be considered a "new lean premix gas-fired stationary combustion turbine". Therefore, if the Hines Energy Complex were an existing major source of HAPs, each new CT would be subject to an emission standard for formaldehyde of no more than 91 ppb by volume, dry (ppbvd at 15% O_2). Compliance is to be demonstrated by initial and annual performance tests. On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY. EPA has stayed the applicability of YYYY to units such as those proposed for the Hines Power Block 4 project, and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

At the allowable emission standard for formaldehyde of no more than 91 ppb by volume, dry (ppbvd at 15% O_2). the proposed CTs would emit the equivalent of 204 lb/10^{12} Btu when firing natural gas and 214 lb/10^{12} Btu when firing light oil. Based on available data (see discussion in Section 2.2), it appears that the proposed Power Block 4 would meet the MACT limits.

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 which 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 4 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 which 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							
		AAQS (µg/m³)			PSD Increments (µg/m³)		
Pollutant	Averaging Time	Primary Standard	Secondary Standard	Florida	Class I	Class II	Significant Impact Levels (µg/m³)[b]
Particulate Matter[c] (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[c]	1-Hour Maximum	157	157	157	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.

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

[b] Maximum concentrations are not to be exceeded.

[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, PM2.5 standards were introduced with a 24-hour standard of 65 g/m³ (3-year average of 98th percentile) and an annual standard of 15 g/m³ (3-year average at community monitors). These standards are not yet applicable and have been challenged at the federal level.

[d] 0.08 ppm for the 8-hour average; achieved when the 3-year average of 99th percentile values is 0.08 ppm or less.

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] ($\mu g/m^3$)
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, by definition, be specific to the project (i.e., case by case).

4.2 New Source Performance Standards

The applicable NSPS for CTs are codified in 40 CFR 60, Subpart GG and summarized in Appendix B. The applicable NSPS emission limit for NO_X is 75 parts per million by volume dry (ppmvd) corrected for heat rate and 15-percent O2. 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 at least 29 times lower than the NSPS when firing natural gas and at least 8 times lower than the NSPS when firing distillate oil.

4.3 Best Available Control Technology (BACT)

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, water injection and SCR for limiting emissions of NO_X, good combustion practices for minimizing CO and VOC emissions, and the use of clean fuels (natural gas) for control of other emissions, including PM_{10} and SO_2. The BACT proposed for the Project is consistent with these permits. The results of the BACT analysis have concluded the following controls as BACT for the Project.

1. The Project will use state-of-the-art DLN combustion technology and SCR to achieve gas turbine exhaust NOx levels of no greater than 2.5 ppmvd corrected to 15-percent O2 when firing natural gas and 10 ppmvd corrected to 15-percent O2 when firing oil.

2. CO emissions when firing natural gas will be limited to 10 ppmvd and when firing distillate oil CO will be limited to 30 ppmvd.

3. VOC emissions when firing natural gas will be limited to 1.8 ppmvd and when firing distillate oil VOC will be limited to 10 ppmvd.

4. Emission rates of PM10 and SO2 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, NSCR, and XONON™ Combustion System were evaluated and determined to be technically infeasible or not commercially demonstrated for the Project. Appendix B presents a discussion of these NO_X control technologies and their feasibility for the Project.

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

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

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

Ammonia injected in the SCR system, which does not react with NO_X, is emitted directly, and referred to as ammonia slip. In general, SCR manufacturers guarantee an ammonia slip to be no more than 9 ppmvd corrected to 15-percent 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 2002, well after the facility is scheduled for construction. The $SCONO_x$™ system has only been operated on a 32-MW facility in California since 1996 and a 5 MW unit in Massachusetts since 1999. The scale up of this complicated technology should not be underestimated. The $SCONO_x$™ technology installed on an "F" Class turbine would involve about a dozen or more different chambers of catalyst for absorption and regeneration. Every 15 to 30 minutes, dampers would be operated to isolate a particular catalyst chamber for regeneration. Each regeneration cycle must isolate the chamber so that 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 SCONOx™ to the DLN combustors (achieving an emission reduction from 25 ppmvd to 3.5 ppmvd) on a CT/HRSG are as follows:

	SCR	$SCONO_x$™	% Difference
Capitol 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	$8,579.0	314

**Although Hines PB 3 was recently permitted with a NOx BACT limit of 2.5 ppmvd, this unit has not yet begun operation. For reasons discussed later in this section, and currently being addressed by the EPRI Low Level NOx Project, there remains concern that the 2.5 ppmvd NOx level can be demonstrated on a continuous basis. Therefore, this BACT analysis will continue to evaluate a comparison between BACT levels of 3.5 ppmvd and 2.5 ppmvd.*

Appendix B contains the detailed cost estimates for the capital and annualized costs. The capital and annualized costs for SCR and SCONOx™ are based on a budgetary cost estimates provided by Englehard and ABB Alstom Environmental Systems, respectively. As shown above, the SCONOx™ capitol 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 SCONOx™ did not include provisions for required mechanical maintenance activities. SCONOx™ control technology clearly has an economic disadvantage compared to SCR, while achieving the same NOx 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)	(%)
0.27	25	100	0.27

The addition of SCR will reduce NO_X emissions by about 650 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 18,184 lb/hr of steam and 81 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 27 MMBtu/hr/unit or 235,000 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 is DLN combustors that prevent the formation of air pollutants within the combustion process, thereby minimizing the amount of add-on controls that can have an impact on the environment. An analogy of this technology is a more efficient automotive engine that gives better mileage and reduces pollutant formation without the need of a catalytic converter.

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

The second unique attribute of the advanced machine is the use of DLN combustors that will reduce NO_X emissions to 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.

<u>NO_x Emission Rate of 2.5 ppmvd Corrected to 15-percent O_2</u>-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 cost for SCR was 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 be exacerbated with even a lower limit. The difficulties include the reliability of the continuous emission monitoring measurement, availability, and stability of calibration gases, precision and accuracy of reference measurements (e.g., EPA Method 7E) and increased ammonia slip. Moreover, there is a general lack of experience in demonstrating compliance over the long term. These concerns are being evaluated by the Electric Power Research Institute (EPRI) Low Level NO_X Project and the project has validated many of these concerns. While this project is still on going, the information to date suggests the potential trend of increasing ammonia injection rates to maintain low NO_X levels and difficulties in monitor performance. The latter included increased span drift and bias test failures during RATA testing.

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 older 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, BACT at 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 produce increased emissions of other air pollutants (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. Although Hines PB 3 was recently permitted with a NO_X BACT limit of 2.5 ppmvd, this unit has not yet begun operation. For reasons discussed in the sections above, and currently being addressed by the EPRI Low Level NO_X Project, there remains concern that the 2.5 ppmvd and 10 ppmvd NO_X levels corrected to 15% O_2 (for gas and oil-firing, respectively) can be demonstrated on a continuous basis. Therefore, although the results of this analysis don't allow the rejection of these levels as BACT, Progress Energy requests that that the BACT determination be revisited, if warranted, based on the actual operating experience of PB 3. The combination of DLN and SCR technology can achieve the maximum amount of emission reduction available, technically feasible and demonstrated for the Project. It remains to be seen whether compliance with these ultralow NO_X limits can be consistently demonstrated, or reliably measured, in actual operation.

$SCONO_x$™ 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

Economic--The estimated capital cost for an oxidation catalyst installed in the HRSG is $1.64 million. The annualized cost of a CO oxidation catalyst is $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 10 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, the as described in the BACT evaluation for NO_X, the use of $SCONO_x$™ on a "F" Class turbine has associated technical uncertainty, as well as significant energy and environmental impacts.

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

The cost effectiveness calculations are significantly understated if the actual emission performance is considered. The actual CO emissions performance of the Siemens Westinghouse 501F turbines (or equivalent) 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 1.8 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	8.5 lb/hr 64.8 lb/hr	Gas Firing; Oil Firing	VE < 10% VE < 20%
Sulfur Dioxide	5.6 lb/hr 105.6 lb/hr	Gas Firing; Oil Firing	Pipeline Natural Gas Distillate Oil (0.05% maximum sulfur)
Nitrogen Oxides	2.5 ppmvd Corrected to 15% O_2	Gas Firing	EPA Method 7E Initial Test; CEM 24-hour Block Average
	10.0 ppmvd Corrected to 15% O_2	Oil Firing	EPA Method 7E Initial Test; CEM 24-hour Block Average
Carbon Monoxide	10 ppmvd 30 ppmvd	Gas Firing; Oil Firing	EPA Method 10 EPA Method 10
Volatile Organic Compounds	1.8 ppmvd 10 ppmvd	Gas Firing; Oil Firing	EPA Methods 18, 25, or 25a EPA Methods 18, 25, or 25a

Note: ppmvd = parts per million, volume dry.

[a] Based on maximum emission rate over turbine inlet operating conditions.
[b] Operating loads from 60 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$_x$™ (2.5 ppmvd @15% O_2)	101	30
Reduction	(692)	(186)

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 Monitoring Applicability

The maximum concentrations predicted for Power Block 4 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 4, ambient air quality monitoring is not required for SO2, PM10, NO2, 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 (O3), annual volatile organic compound (VOC) emissions from Power Block 4 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 4 is exempt from preconstruction monitoring for these pollutants.

Table 5-1
Summary Of Maximum Modeled Power Block 4 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	2.7	13	NO
Particulate Matter (PM_{10})	24-Hour	1.6	10	NO
Nitrogen Dioxide (NO_2)	Annual	0.14	14	NO
Carbon Monoxide (CO)	8-Hour	23	575	NO
Volatile Organic Compounds (VOC)	Annual	57	100 TPY	NO

Source: Golder, 2004.

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 4 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 ISCST 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. Power Block 2 is now in operation. In 2002, Hines Energy Complex submitted a PSD application for Power Block 3. Power Block 3 is now in the construction phase.

Hines Power Block 4 represents a new project for the Hines Energy Complex, subject to PSD review. For this PSD application, Project impacts resulting from Power Block 4 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 inlet temperatures; and fuel oil firing at 100%, 80%, and 65% load at 20°F, 59°F, and 105°F compressor air inlet 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. Complete ISCST3 model outputs will be submitted to the FDEP under separate cover.

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 Progress Energy 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 4 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 ISCST 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

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 4

7.1.1 Worst-case Operation Analysis

As indicated in Section 6.4.1, the proposed Power Block 4 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 4 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. A complete set of the ISCST3 model output files have been submitted to the FDEP under separate cover.

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 4 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 4 Compared To The PSD Class Ii Significant Impact Levels

Pollutant	Averaging Period	Maximum Predicted Concentration [a] ($\mu g/m^3$)	Polar Location [b]		Year	Significant Impact Level ($\mu g/m^3$)	Distance to Significant Impact Level (km)	Predicted Impact Greater than the Significant Impact Level? (Yes/No)
			Dir. (deg.)	Dist. (m)				
Carbon Monoxide	1-Hour	63	290	1000		2,000	None	No
	8-Hour	22.9	170	500		500	None	No
Nitrogen Dioxide	Annual	0.066	20	2000		1	None	No
Sulfur Dioxide	3-Hour	13.0	140	500		25	None	No
	24-Hour	2.7	94	1304		5	None	No
	Annual	0.037	20	2000		1	None	No
Particulate Matter (PM_{10}) [c]	24-Hour	1.6	94	1304		5	None	No
	Annual	0.039	20	2000		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, 2004.

TABLE 7-2
Summary Of Maximum Concentrations Predicted For Power Block 4 Compared To The PSD Class I Significant Impact Levels

Pollutant	Averaging Period	Maximum Concentration Predicted for Power Block 4 [(a)] ($\mu g/m^3$)	PSD Class I Significant Impact Level ($\mu g/m3$)	Predicted Impact Greater than the PSD Significant Impact Level? (Yes/No)
Sulfur Dioxide (SO_2)	3-Hour	0.52	1.0	NO
	24-Hour	0.17	0.2	NO
	Annual	0.001	0.1	NO
Particulate Matter (PM_{10})	24-Hour	0.12	0.3	NO
	Annual	0.001	0.2	NO
Nitrogen Dioxide (NO_2)	Annual	0.001	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, 2004

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, Progress Energy is providing a general assessment of the impact of Power Block 4 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 4, and approximately 6 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 3 of the 6 new operational employees will migrate into the Polk County area. Based on the average household size of 2.53 persons, a total of 8 persons (workers and their families) are predicted to move into the area as a result of Power Block 4. 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 Progress Energy'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 proposed 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 4 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; and
- 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.

8.3.1.1 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 intercostals 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 0.516, 0.343, and 0.171 $\mu g/m^3$, respectively, at the Class I area. The maximum 3-hour average SO_2 concentrations predicted for the Project at the Class I areas are approximately 0.25 percent 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.

8.3.1.2 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 $\mu g/m^3$ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

The maximum 1-, 3-, and 8-hour average NO_2 concentrations due to the Project are predicted to be 0.418, 0.223, and 0.078 $\mu g/m^3$, respectively, at the Class I area. These concentrations are approximately 0.002 to 0.011 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 0.001 $\mu g/m^3$ at the Class I area, which is 0.000025 to 0.00005 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.

8.3.1.3 Particulate Matter

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

The maximum 8-hour PM concentration due to the Project is predicted to be 0.23 $\mu g/m^3$ at the Class I area. This concentration is approximately 0.06 to 0.11 percent of the values that affected plant foliage. As a result, no significant effects to vegetative AQRVs are expected from the Project's emissions.

8.3.1.4 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 $\mu g/m^3$) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik *et al.* (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85 x 10^5 $\mu g/m^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

The maximum 1-hour average concentration due to the Project is 0.739 $\mu g/m^3$ in the Class I area which is less than 0.001 percent of the minimum value that caused inhibition in laboratory studies. The amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season. The maximum predicted annual concentration of 0.011 $\mu g/m^3$ 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.

8.3.1.5 Sulfuric Acid Mist

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

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

8.3.1.6 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 4 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 NWR.

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 that 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

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

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

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

b_{extb} is the background extinction coefficient.

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

Processing of visibility impairment for this study was performed with the CALPUFF model (see Appendix 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.

8.4.3 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 0.86 percent for the natural gas operation and 4.53 percent for fuel oil operation. These values are below the FLM's screening criteria of 5 percent for both natural gas and fuel oil operation. As a result, the change in visibility due to the Project's emissions 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:

- SO2, wet and dry deposition; and
- SO4, wet and dry deposition.

The CALPOST model produced deposition results in units of $g/m^2/s$. 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 0.0011 and 0.0017 kg/ha/yr, respectively. These maximum deposition rates are well 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] 1990	1992	1996
Natural Gas				
SO_2	Annual	0.0003	0.0003	0.0004
	24-Hour	0.007	0.009	0.008
	8-Hour	0.016	0.018	0.019
	3-Hour	0.020	0.022	0.028
	1-Hour	0.024	0.028	0.035
PM_{10}	Annual	0.0006	0.0006	0.0008
	24-Hour	0.011	0.016	0.014
	8-Hour	0.025	0.029	0.032
	3-Hour	0.036	0.038	0.047
	1-Hour	0.040	0.046	0.059
NO_2	Annual	0.0006	0.0008	0.0008
	24-Hour	0.024	0.025	0.027
	8-Hour	0.065	0.073	0.076
	3-Hour	0.079	0.097	0.114
	1-Hour	0.097	0.124	0.143
CO	Annual	0.005	0.004	0.005
	24-Hour	0.060	0.098	0.079
	8-Hour	0.143	0.173	0.174
	3-Hour	0.193	0.210	0.257
	1-Hour	0.217	0.290	0.321
Backup Fuel Oil				
SO_2	Annual [c]	0.001	0.001	0.001
	24-Hour	0.105	0.171	0.143
	8-Hour	0.273	0.321	0.343
	3-Hour	0.351	0.422	0.516
	1-Hour	0.385	0.523	0.632
PM_{10}	Annual [c]	0.001	0.001	0.001
	24-Hour	0.078	0.119	0.110
	8-Hour	0.175	0.214	0.229
	3-Hour	0.247	0.298	0.347
	1-Hour	0.269	0.362	0.425
NO_2	Annual [c]	0.0007	0.0009	0.0010
	24-Hour	0.066	0.073	0.078
	8-Hour	0.186	0.196	0.223
	3-Hour	0.208	0.264	0.341
	1-Hour	0.259	0.313	0.418
CO	Annual [c]	0.010	0.010	0.011
	24-Hour	0.144	0.230	0.193
	8-Hour	0.325	0.385	0.399
	3-Hour	0.429	0.521	0.603
	1-Hour	0.467	0.629	0.739

[a] Concentrations are highest predicted using CALPUFF model and CALMET wind fields for central Florida, 1990, 1992, and 1996.

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

[c] Annual average concentrations for fuel oil are based on 1000 hours fuel oil firing and 7760 hours natural gas firing per year.

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/m³ (0.5 - 1.0 ppm)	790 - 1,570 µG/m³ (0.3 - 0.6 ppm)	Ragweeds Legumes Blackberry Southern pines Red and black oaks White ash Sumacs
Intermediate	2,620 - 5,240 µG/m³ (1.0 - 2.0 ppm)	1,570 - 2,100 µG/m³ (0.6 - 0.8 ppm)	Maples Locust Sweetgum Cherry Elms Tuliptree Many crop and garden species
Resistant	>5,240 µG/m³ (>2.0 ppm)	>2,100 µG/m³ (>0.8 ppm)	White oaks Potato Upland cotton Corn Dogwood Peach

[a] Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

Source: EPA, 1982a.

Table 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 (%)
	1990	1992	1996	
Natural Gas	0.64	0.56	0.86	5.0
Backup Fuel Oil	4.10	4.52	4.53	5.0

[a] Concentrations are highest predicted using CALPUFF model and CALMET wind fields for central Florida, 1990, 1992 and 1996.
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 20F.

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[b]
	1990		1992		1996		
Species/Operating Mode	(g/m2/s)	(kg/ha/yr)					(kg/ha/yr)
Nitrogen (N) Deposition							
Natural Gas only[c]	1.652E-12	0.0005	2.185E-12	0.0007	1.753E-12	0.0006	0.01
With 1000 hours Fuel Oil[d]	2.515E-12	0.0008	3.383E-12	0.0011	2.590E-12	0.0008	0.01
Sulfur (S) Deposition							
Natural Gas only[c]	1.347E-12	0.0004	1.755E-12	0.0006	1.472E-12	0.0005	0.01
With 1000 hours Fuel Oil[d]	4.008E-12	0.0013	5.333E-12	0.0017	4.554E-12	0.0014	0.01

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

g/m2/s x	0.001	kg/g
x	10000	m^2/hectare
x	3600	sec/hr
x	8760	hr/yr =kg/ha/yr
or		
$g/m^2/s$ x	3.1536E+08 =	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 based on 8760 hours natural gas firing.

9.0 REFERENCES

Allaway, W. H. 1968. Agronomic Controls over the Environmental Cycling of Trace Elements. In: Norman, A. G. (ed.). Advances in Agronomy. Vol. 20, Academic Press, New York.

Aller, A. Javier, J. Luis Bernal, M. Jesus del Nozal, and Luis De ban. 1990. Effects of Selected Trace Elements in Plant Growth. J Sci Food Agric 51:447-479.

Barrett, T. W. and H. M. Benedict. 1970. Sulfur Dioxide. In: Recognition of Air Pollution Injury to Vegetation: A Pictorial Atlas. Jackobsen, J. S. and A. C. Hill (eds.). Air Pollution Control Association. Pittsburgh, Pennsylvania.

Bazzay, F. A., G. L. Rolfe, and R. W. Carlson. 1974. Effects of Cadmium on Photosynthesis and Transpiration of Excised Leaves of Corn and Sunflower. Physiologic Plantarum. 32:373-376.

Bell, D. E. and W. H. Rickard. 1974. Environmental Impact Monitoring of Nuclear Power Plants. Part 7 - Terrestrial Ecology. Battelle Pacific Northwest Laboratories. Richland, Washington.

Black & Veatch. 1992. Technical Data on Emissions in support of FPC Polk County Site Project. Kansas City, Missouri.

Boericke, R. R. 1990. Emission Controls and Costs for Gas Turbine Applications. In: 34th General Electric Turbine State-of-the-Art Technology Seminar for Architect-Engineers and Engineer Constructors.

Bowen, H.J.M. 1966. Trace Elements in Biochemistry. Academic Press, New York.

Chapman, H.D. (ed) 1966. Diagnostic Criteria for Plants and Soils. University of California, Riverside. Division of Agricultural Sciences.

Chappelka, A.H., B.I. Chevone, and T.E. Burk. 1988. Growth Response of Green and White Ash Seedlings to Ozone, Sulfur Dioxide and Simulated Acid Rain. Forest Science 34:1016-1029.

Davis, Donald D., and John M. Shelly. 1992. Growth Response of Four Species of Eastern Hardwood Tree Seedlings Exposed to Ozone, Acidic Precipitation and Sulfur Dioxide. J. Air Waste Management Assoc 42:309-311.

deSteiguer, J.E., John M. Pye, and Carolyn S. Love. 1990. Air Pollution Damage to U.S. Forests. A Survey of Perceptions and Estimates by Scientists. Journal of Forestry 17-22.

Dvorak, A. J. and E. D. Pentecost, et al. 1977. Assessment of the Health and Environmental Effects of Power Generation in the Midwest. Vol. II, Ecological Effects (Draft Report) Argonne National Laboratory. Argonne, Illinois. As cited in FWS, 1978.

Edgerton, E.S. and T.F. Lavery. 1990. Wet and Dry Deposition Across the Southeastern United States. In: Proceeding of the Florida Acidic Deposition Conference, Catis E. Watkins, ed. Tampa, Florida.

EPA (U.S. Environmental Protection Agency). 1991. New Source Review (NSR) Program Transition Guidance. Memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, Research Triangle Park, NC. March 11.

EPA. 1990. BACT/LAER Clearinghouse - A Compilation of Control Technology Determinations. EPA 450/3-90-015b. Prepared for the Office of Air Quality by PEI Associates Inc., Cincinnati, Ohio.

EPA. 1990b. New Source Review Workshop Manual (Draft). Office of Air Quality Planning and Standards. October.

EPA. 1990c. "Top Down" Best Available Control Technology Guidance Document (Draft). Office of Air Quality Planning and Standards. March 15.

EPA. 1988. Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and Sources. EPA-450/2-88-006a. Prepared for the EPA by Radian Corporation. Research Triangle Park, North Carolina.

EPA. 1988a. Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, AP-42, Supplement B. September.

EPA. 1998 Industrial Source Complex (ISC) Dispersion Model User's Guide Volumes I and II.

EPA. 1985. BACT/LAER Clearinghouse - A Compilation of Control Technology Determinations. EPA 450/3-85-016b. Prepared for the Office of Air Quality by PEI Associates Inc., Cincinnati, Ohio.

EPA. 1985a. Final Stack Height Regulation. Federal Register, Volume 50. Page 27892. July 8.

EPA. 1976. Diagnosing Vegetation Injury Caused by Air Pollution. Developed for EPA by Applied Science Associates, Inc., EPA Contract No. 68-02-1344.

EPA. 1973. Air Pollution Engineering Manual (AP-40). Research Triangle Park, NC.

ESE (Environmental Science & Engineering). 1989. Florida Acid Deposition Monitoring Program - 1988 Summary Report. PB91-100305. Gainesville, Florida.

ESE. 1988. Florida Acid Deposition Monitoring Program - 1987 Summary Report. PB89-152532. Gainesville, Florida.

ESE. 1987. Florida Acid Deposition Study: Five Year Data Summary; PB88-158779. Gainesville, Florida.

ESE. 1986. Florida Acid Deposits Study, Final Report, A Synthesis of the Florida Acid Deposition Study; PB86-243359. Gainesville, Florida.

Federation of American Societies for Experimental Biology. 1973. Effects of Low Concentrations of Sulfur Concentrations of Sulfur Dioxide on Vascular Plants. (Table). Biology Data Book, pp. 995-1015.

FDEP (Florida Department of Environmental Protection). 1998. Air Quality Database.

FPC (Florida Power Corporation). 1992. Site Certification Application for Engineering and Licensing of the Polk County Site.

Foy, C.D. 1964. Toxic Factors in Acid Soils of the Southwestern United States as Related to the Response of Alfalfa to Lime. U.S. Dept. Agric. Prod. Res. Report 80.

Gough, L.P., H.T. Schacklette, and A.A. Case. 1979. Element Concentrations Toxic to Plants, Animals, and Man. Geological Survey Bulletin 1466, U.S. Department of Interior, Washington, D.C.

Gough, P., and H.T. Shacklette. 1976. Toxicity of Selected Elements to Plants, Animals, and Man - An Outline. In: Geochemical Survey of the Western Energy Regions, Third Annual Progress Report, July. Appendix IV. U.S. Dept. of Interior. Geological Survey.

Hart, Robin, Patricia G. Webb, R. Hilton Biggs, and Kenneth M. Portier. 1988. The Use of Lichen Fumigation Studies to Evaluate the Effects on New Emission Sources or Class I Areas. J. Air Pollut Control Assoc. 38:144-147.

Heggestad, H. E. and W. W. Heck. 1971. Nature, Extent, and Variations of Plant Responses to Air Pollutants. Advances in Agronomy 23:111-145.

Hogsett, W.E., M. Plocher, V. Wildman, D.T. Tingey, and J.P. Bennett. 1985. Growth Responses of Two Varieties of Slash Pine Seedlings to Chronic Ozone Exposures. Canada Journal of Botany 63:2369-2376.

Huber, A. H. and W. H. Snyder. 1976. Building Wake Effects on Short Stack Effluents. Preprint Volume for the Third Symposium on Atmospheric Diffusion and Air Quality. American Meteorological Society, pp 235-242.

Hyde, Adam G., Lloyd Law, Jr., Robert L. Weatherspoon, Melvin D. Cheyney, and Joseph J. Echenrode. 1977. Soil Survey of Hernando County, Florida. U.S. Department of Agriculture Soil Conservation Service.

Jacobsen, J.S. 1977. Sulfur Dioxide Air Quality Standards for the Prevention of Losses to Agriculture and Forestry in California. Report to the State of California Air Resources Board (CARB). The Boyce Thompson Institute. Yonkers, New York.

Jensen, Keith F. and Leon S. Dochinger. 1989. Response of Eastern Hardwood Species to Ozone, Sulfur Dioxide and Acid Precipitation. Journal of the Air Pollutant Control Assoc 39:852-855.

Jones, H.C., D. Weber, and D. Balsillie. 1974. Acceptable Limits for Air Pollution Dosages and Vegetation Effects: Sulfur Dioxide. Presented at the 65th Annual Meeting of the Air Pollution Control Association. Denver, Colorado. Paper No. 74-225.

Kamprath, E. J. 1972. Possible Benefits from Sulfur in the Atmosphere. Combustion. 16-17.

Kothny, E.L. 1973. Trace Elements in the Environment. American Chemical Society. Washington, D.C.

Krause, G.H.M. and H. Kaiser. 1977. Plant Response to Heavy Metal and Sulfur Dioxide. Environmental Pollution 12:63-71.

Ledbetter, M.C., P.W. Zimmerman, and A.E. Hitchcock. 1959. The Histopathological Effects of Ozone on Plant Foliage. Contrib. Boyce Thompson Inst. 20:275-282.

Linzon, S.N. 1973. Sulfur Dioxide Air Quality Standards for Vegetation. Presented at the 60th Annual Meeting of the Air Pollution Control Association. Chicago, Illinois. Paper No. 73-107.

Lisk, D. 1972. Trace Metals in Soils, Plants, and Animals. Advances in Agronomy 24:267-325.

Loomis, R.C. and W.H. Padgett. 1973. Air Pollution and Trees in the East. U.S. Department of Agriculture, Forest Service.

MacLean, David C., Delbert C. McCune, Leonard H. Weinstein, Richard H. Maudl, and George N. Woodruff. 1968. Effects of Acute Hydrogen Fluoride and Nitrogen Dioxide Exposures on Citrus and Ornamental Plants of Central Florida. Environmental Science and Technology 2:444-449.

Matsushima, J. and R.F. Brewer. 1972. Influence of Sulfur Dioxide and Hydrogen Fluoride as a Mix or Reciprocal Exposure on Citrus Growth and Development. J. Air Pollution Control Assoc 22:710-713.

Moore/Bowers Group. 1992. Polk County Site, Socioeconomic and Demographic Support Data. Tampa, Florida.

NAPAP. 1991. The U.S. National Acid Precipitation Assessment Program - 1990 Integrated Assessment Report. The NAPAP Office of the Director. Washington, D.C.

NAPAP. 1991a. Acid Deposition: State of the Science and Technology. Summary Report of the U.S. National Acid Precipitation Assessment Program. Office of the Director. Washington, D.C.

NAS (National Academy of Science). 1974. Committee on Biological Effects of Atmospheric Pollutants. Medical and Biological Effects of Environmental Pollutants - Chromium. NAS. Washington, D.C.

Newman, James R. and R.K. Schreiber. 1988. Air Pollution and Wildlife Toxicology: An Overlooked Problem. Environmental Toxicology and Chemistry 7:381-390.

Newman, James R. 1980. Effects of Air Emissions on Wildlife Resources U.S. Fish and Wildlife Report FWS/OBS-80/40.1. U.S. Fish and Wildlife Service. Biological Services Program, National Power Plant Team. 32 pp.

North Carolina DNR (Department of Natural Resources and Community Development). 1985. A Screening Method for PSD. Letter from Mr. Eldewins Haynes, North Carolina DNR to Mr. Lewis Nagler, U.S. Environmental Protection Agency, Region IV. July 22.

Okano, K., T. Machicla, and T. Toxsuka. 1989. Differences in Ability of NO_2 Absorption in Various Broad-leaved Tree Species. Environmental Pollution 58:1-17.

Olsen, R. A. 1957. Absorption of Sulfur Dioxide from the Atmosphere by Cotton Plants. Soil Science 84:107-111.

Pilny, Paul E., Charles T. Grantham, Joseph N. Seluister, and Daniel L. Stanley. 1988. Soil Survey of Citrus County Florida. U.S. Department of Agriculture Soil Conservation Service.

Radian Corporation. 1991. Gas Turbine Selective Catalytic Reduction Procurement Guidelines. In: Electric Power Research Institute (EPRI) Publication 65-7254.

Ragput, C.B.S., D.P. Ormrod, and W.D. Evans. 1977. The Resistance of Strawberry to Ozone and Sulfur Dioxide. Plant Disease Reporter 61:222-225.

Reuther, W., P.F. Smith, and A. W. Specht. 1949. A Comparison of the Mineral Composition of Valencia Orange Leaves from the Major Producing Areas of the U.S. Proc. Fla. State Hortic. Soc. 62:38-45.

Shackelette, Hansford T. and Josephine G. Boerngen. 1984. Element Concentrations in Soils and Other Surficial Materials of the Conterminous United States. U.S. Geological Survey Professional Paper 1270. U.S. Geological Survey. Washington, D.C. 105 pp.

Shanklin, J. and T.T. Kozlowski. 1985. Effect of Flooding of Soil on Growth and Subsequent Responses of Taxodium distichum Seedlings to SO_2. Environmental Pollution 38:199-212.

Shorr, Marvin M. 1991. NO_X Control for Gas Turbines: Regulations and Technology. The Cogeneration Journal 6(2):20-52.

Sucoff, E. and W. Baily. 1971. Relative Tolerance of Woody Plants Grown in Minnesota to Five Air Pollutants - Air Compilation of Ratings. Minnesota Forestry Research Notes. No. 227.

Taylor, O.C. and D.C. MacLean. 1970. Nitrogen Oxides and the Peroxyacyl Nitrates. In: Recognition of Air Pollution Injury to Vegetation: A Pictorial Atlas. Jacobsen, J.S. and A.C. Hill (eds). Air Pollution control Association. Pittsburgh, Pennsylvania.

Terman, G.L. 1978. Atmospheric Sulphur - The Agronomic Aspects. Technical Bulletin Number 23. The Sulphur Institute. Washington, D.C.

Thompson, C.R., E.G. Hensel, G. Kats, and O.C. Taylor. 1970. Effects of Continuous Exposure of Navel Oranges to Nitrogen Dioxide. Atmospheric Erosion 4:349-355.

Thompson, C. Ray, and O.C. Taylor. 1969. Effects of Air Pollutants on Growth, Leaf Drop, Fruit Drop and Yield of Citrus Trees. Environmental Science and Technology 3:934-940.

Thompson, C. Ray, O.C. Taylor, M.D. Thomas, and J.O. Ivie. 1967. Effects of Air Pollutants on Apparent Photosynthesis and Water Use by Citrus Trees. Environmental Science and Technology 1:644-650.

Thompson, C.R., D.T. Tingey, and R.A. Reinert. 1974. Acceptable Limits for Air Pollution Dosages and Vegetation Effects: Nitrogen Dioxide. Presented at 67th Annual Meeting of Air Pollution Control Association. Denver, Colorado. Paper No. 74-227.

Tingey, D.T., R.A. Reinert, J.A. Dunning, and W.W. Heck. 1971. Vegetation Injury from the Interaction of Nitrogen Dioxide and Sulfur Dioxide. Phytopathology 61:1506-1511.

Tingey, D.T., R.A. Reinert, C. Wickliff, and W.W. Heck. 1973a. Chronic Ozone and/or Sulfur Dioxide Exposures Affect the Early Vegetation Growth of Soybean. Canadian Journal of Plant Science 53:875-879.

Tingey, D.T., R.A. Reinert, J.A. Dunning, and W.W. Heck. 1973b. Foliar Injury Responses of Eleven Plant Species to Ozone/Sulfur Dioxide Mixtures. Atmospheric Environment 7:201-208.

Treshow, M. 1970. Ozone Damage to Plants. Environmental Pollution 1:155-161.

Turner, D. B. 1970. Workbook of Atmospheric Dispersion Estimates. U.S. Environmental Protection Agency. AP-26.

U.S. Fish and Wildlife Service. 1996. Air Quality and Air Quality Related Values in Chassahowitzka National Wildlife Refuge and Wilderness Area. Department of the Interior. Denver, Colorado.

Valkovic, V. 1975. Trace Element Analysis. Halsted Press. New York. 229 pp.

White, K.L., A.C. Hill, and J.H. Bennett. 1974. Synergistic Inhibition of Apparent Photosynthesis Rate of Alfalfa by Combinations of Sulfur Dioxide and Nitrogen Dioxide. Environmental Science and Technology 6:574-576.

Woodman, James N. 1987. Pollution-induced Injury in North American Forests: Facts and Suspicions. Tree Physiology 3:1-5.

Zeevaert, A.J. 1976. Some Effects of Fumigating Plants for Short Periods with NO_2. Environmental Pollution 11:97-107.

APPENDIX A

EMISSION ESTIMATES

Table A-1. Design Information and Stack Parameters for the Progress Energy 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
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)/ft²

BEST AVAILABLE COPY

Table A-2. Maximum Emissions for Criteria and Other Regulated Pollutants for the Progress Energy 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 $(NH_4)_2$ SO_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]	2.5	2.5	2.5	2.5
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	18.0	16.5	16.0	15.1
(TPY)	78.7	72.1	69.9	66.1
[Ratio lb/hr provided/calculated]	1.390	1.403	1.397	1.404
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
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 Progress Energy 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	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 Progress Energy Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 100 % Load

Parameter	20 °F	59 °F	72°F	90°F
	Ambient/Compressor Inlet Temperature			
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
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 Progress Energy 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)/ft²

Table A-6. Maximum Emissions for Criteria and Other Regulated Pollutants for the Progress Energy 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
Particulate from CT and SCR			
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 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	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]	2.5	2.5	2.5
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	14.7	13.7	12.6
(TPY)	64.4	59.8	55.3
[Ratio lb/hr provided/calculated]	1.401	1.399	1.402
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 ppmvd	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_2 - 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 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 2.8 ppmvd at 15% oxygen.

Table A-7. Maximum Emissions for Other Regulated PSD Pollutants for the Progress Energy 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 Progress Energy 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
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
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 Progress Energy Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 60% 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 (%)	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)/ft²

NSPS Calculation:

Heat Rate at 59oF	10,610 Btu/kWh (LHV)
	11.19355 kJ/W
	14.4 kJ/W (NSPS)
	75 ppmvd @ 15% O2
	96.48 ppmvd @ 15% O2

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

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	90 °F
Hours of Operation	3,000	3,000	3,000
<u>Particulate from CT and SCR</u>			
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 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	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)	2.5	2.5	2.5
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	12.0	11.4	10.5
(TPY)	18.0	17.1	15.7
[Ratio lb/hr provided/calculated]	1.400	1.398	1.394
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 ppmvd	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.
(e) For VOC emissions, data originally provided at 2.8 ppmvd at 15% oxygen.

Note: ppmvd= parts per million, volume dry; O2= oxygen.

facvoc60 1.00

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

Parameter	Ambient/Compressor Inlet Temperature 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.

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

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

Parameter	Ambient/Compressor Inlet Temperature 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
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.

Total HAPs	2.02E-02	1.92E-02	1.77E-02

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

Parameter		Turbine Inlet Temperature 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)/ft²; 14.7 lb/ft³
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 Progress Energy Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 100 % Load

Parameter	Turbine Inlet Temperature 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	10	10	10	10
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	77.0	73.0	70.7	64.4
(TPY)	38.5	36.5	35.4	32.2
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 Progress Energy Hinės Energy Center Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 100 % 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)	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 Progress Energy Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 100 % 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)	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
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 Progress Energy 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
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)/ft²; 14.7 lb/ft³

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 Progress Energy 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
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	10	10	10	10
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	64.4	60.0	57.9	53.3
(TPY)	32.2	30.0	28.9	26.7
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 (%)	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

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)	1,644	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
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)/ft²; 14.7 lb/ft³
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

Parameter	Turbine Inlet Temperature 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	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 $(NH_4)_2SO_4$/ 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 $(NH_4)_2SO_4$/ 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	10	10	10	10
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	54.1	50.6	49.5	46.2
(TPY)	27.0	25.3	24.8	23.1
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

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)	1.38E+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
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

	Annual Emissions (tons/year)[a]			Maximum Emissions (tons/year)[b]				PSD
	Natural Gas	Natural Gas	Distillate Oil	Case A	Case B	Case C	Case D	Significant
Load:	100%	60%	100%					Emission Rates
Pollutant 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	72	17	36	72.1	64.5	100.4	92.7	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
Lead	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
MWC Organics (as 2,3,7,8-TCDD)	9.62E-09	2.30E-09	3.67E-07	9.6E-09	8.6E-09	3.8E-07	3.7E-07	3.50E-06
MWC Metals (Be & Cd)	0.0	0.0	3.4E-03	0.0E+00	0.0E+00	3.4E-03	3.4E-03	15
MWC Acid Gases (HCL)	0.0	0.0	0.2	0.0	0.0	0.2	0.2	40.0
Total HAPs	1.95	1.27	0.79	1.9	2.5	2.5	3.1	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	144	34	73	144	129	201	185	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
MWC Organics (as 2,3,7,8-TCDD)	1.92E-08	4.61E-09	7.34E-07	1.92E-08	1.73E-08	7.51E-07	7.49E-07	3.50E-06
MWC Metals (Be & Cd)	0.00E+00	0.00E+00	6.90E-03	0.00E+00	0.00E+00	6.90E-03	6.90E-03	15
MWC Acid Gases (HCL)	0.0	0.00	0.40	0.00	0.00	0.40	0.40	40.0
Total HAPs	3.9	2.53	1.58	3.90	5.10	5.03	6.23	25

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

Table A-26. Maximum Formaldehyde Emissions for Hines Power Block 4 Combined-Cycle Expansion Project
Siemens-Westinghouse 501F, Dry Low NOX Combustor, Natural Gas, 100 % Load

Parameter	CT Only Turbine Inlet Temperature and Load 100% 20 °F	 100% 59 °F	 100% 72°F	 100% 90°F
Formaldehyde (CH_2O) MW =	30			
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT, ppmvd @15% O_2	0.091	0.091	0.091	0.091
Moisture (%)	7.77	8.39	9.45	11.64
Oxygen (%)	12.52	12.53	12.32	11.99
Turbine Flow (acfm)	2,567,660	2,433,641	2,379,291	2,339,045
Turbine Exhaust Temperature (°F)	1,086	1,107	1,118	1,148
CT Emission rate (lb/hr)	0.427	0.391	0.379	0.358
CT Emission rate (TPY)	1.87	1.71	1.66	1.57
Heat Input (MMBtu/hr, HHV)	2012	1915	1771	1705
CT Emission rate (lb/10^{12} Btu)	212.1	204.1	213.9	210.2

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

Golder Associates, 2004

Table A-27. Formaldehyde Emissions for Hines Power Block 4 Combined-Cycle Expansion Project
Siemens-Westinghouse 501F, Dry Low NOX Combustor, Natural Gas, 60 % Load

		CT Only Turbine Inlet Temperature and Load	
	20 °F	59 °F	90°F
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]			
CT, ppmvd @15% O_2	0.091	0.091	0.091
Moisture (%)	7.18	7.89	9.17
Oxygen (%)	13.18	13.08	13.08
Turbine Flow (acfm)	1,864,103	1,808,271	1,708,519
Turbine Exhaust Temperature (°F)	1,088	1,112	1,083
CT Emission rate (lb/hr)	0.285	0.270	0.249
CT Emission rate (TPY)	1.25	1.18	1.09
Heat Input (MMBtu/hr, HHV)	2012	1915	1705

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

Golder Associates, 2004

Table A-28. Maximum Formaldehyde Emissions for Hines Power Block 4 Combined-Cycle Expansion Project
Siemens-Westinghouse 501F, Dry Low NOX Combustor, Distillate, 100 % Load

Parameter	CT Only Turbine Inlet Temperature and Load			
	100% 20 °F	100% 59 °F	100% 72 °F	100% 105 °F
Formaldehyde (CH_2O) MW = 30				
CH_2O (lb/hr) = CH_2O (ppmvd@ 15% O_2) x {[20.9 x (1-Moisture (%)/100] - Oxygen, dry(%)} x 2116.8 lb/ft^2 x Volume flow (acfm) x 30 (mole. wgt CH2O) x 60 min/hr / [1545 x (CT temp.(°F) + 460) x (20.9-15) x 1,000,000 (adj. for ppm)]				
CT, ppmvd @15% O_2	0.091	0.091	0.091	0.091
Moisture (%)	7.12	7.74	8.79	11.04
Oxygen (%)	11.99	11.99	11.78	11.4
Turbine Flow (acfm)	2,475,210	2,434,870	2,379,489	2,222,073
Turbine Exhaust Temperature (°F)	1,070	1,100	1,110	1,130
CT Emission rate (lb/hr)	0.457	0.433	0.420	0.382
CT Emission rate (TPY)	2.00	1.90	1.84	1.67
Heat Input (MMBtu/hr, HHV)	2100	2020	1870	1707
CT Emission rate (lb/10^{12} Btu)	217.5	214.3	224.5	224.1

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

Golder Associates, 2004

APPENDIX B

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) FOR THE COMBUSTION TURBINES

B.1 NEW SOURCE PERFORMANCE STANDARDS

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

B.1.1 SUBPART GG

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

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100 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.1.2 SUBPART DA

On September 16, 1998, the NSPS for fossil fuel fired steam electric generators with more than 250 MMBtu/hr heat input were updated to include generally more stringent emission limitations for NO_x. These revised NSPS (Subpart Da) apply to any affected facility, which commenced construction after July 9, 1997. The applicable NO_x NSPS limit for firing coal, oil or natural gas, or a mixture of these, or any other fuels, is 1.6 lb/MW [40 CFR 60.44a(d)(1)]. For combined cycle projects, these NSPS are applicable to duct burners associated with supplemental firing of the HRSGs. As there are no duct burners proposed for PB 4, this NSPS standard is not applicable.

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 9 ppmvd (corrected to 15-percent O_2) when firing natural gas.

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

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

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

Other available control technologies that have become available for controlling NO_x emissions from combustion turbines for include SCONO$_x$™ and XONON™. SCONO$_x$™ is an add-on control using absorption and chemical conversion to remove NO_x formed from combustion, while XONON™ is a catalytic combustion system integral to the turbine. Other potential technologies used in combustion process for NO_x removal include: NO$_x$OUT, Thermal DeNO$_x$, and NSCR.

Technology Descriptions and Feasibility

Wet Injection

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

Dry Low-NO_x Combustor

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

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

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

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

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

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

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

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

XONON™ Catalytic Combustor

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

NO_xOUT Process

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

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

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

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

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
2. Sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

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

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

Thermal DeNO$_x$

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

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

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

Nonselective Catalytic Reduction

Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. CTs have the required temperature but also have high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for CTs.

<u>Technology Demonstration and Feasibility</u>

The combustion controls using dry low-NO_x combustors for the combustion turbine and low-NO_x burners for duct firing are available, demonstrated and technically feasible for combustion turbines in either simple cycle or combined cycle configuration. The dry low-NO_x combustion technology alone can achieve 9 ppm (corrected to 15 percent O_2 dry conditions) when firing natural gas.

The technical evaluation of post-combustion gas controls that include NO_xOUT, Thermal $DeNO_x$, and NSCR, and indicate that these processes have not been applied to either simple cycle combustion turbines or combined cycle systems and are technically infeasible for the project because of process constraints (e.g., temperature). The $SCONO_x$™ control technology is available but not considered to be technically feasible because it has not been commercially demonstrated on large "F" Class CTs. The CTs planned for the project, 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.

Technology	Combined Cycle 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, 1999-2004

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	3.5 ppm NG; 41 ppm w/ FO	DLN/SCR;WI		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.95 ppm NG; 11.3 ppm FO	DLN/SCR; WI/SCR		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	DLN/SCR		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	3.5 ppm / 0.013 lb/MMBtu	DLN/SCR		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		For NO_x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0.013 lb/MMBtu	SCR		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.013/0.048 lb/mmbtu NG/FO - GE; 0.013/0.046 lb/mmbtu	SCR/WI		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu)	SCR - CC, DLN-SC	an/1-hr	8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.013 lb/mmBtu (30.7 lb/hr)	SCR	3-hr	
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	3.5 ppm (0.013 lb/mmBtu)	SCR		
Tenaska Alabama IV Partners	AL	Oct-01	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	Oct-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		SCONOx - $18760/ton NOX; 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
Barton Shoals Energy, LLC	AL	Jul-02	1,200	4	4	GE 7FA (170 MW)	NG	CC	8,760	2.5 ppm (0.0092 lb/mmbtu)	SCR		EPA did not received application until 5/24/02
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		
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

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2004

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
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	Mar-02	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	May-02	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	Jan-02	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	Jan-02	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	Aug-02	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	Jan-02	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)
CPV Cana Power Generation Facility	FL	01/17/2002	245	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG; 10 ppm FO	SCR		PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load
FPL Martin	FL	04/16/2003	1,150	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 5000 FO/1,000; 500 FO	2.5 ppm NG; 10 ppm FO/9-15 ppm NG; 42 ppm FO	SCR/DLN; WI		PA = Power Augmentation
FPL Manatee	FL	04/15/2003	1,150	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	2.5 ppm CC/9-15 ppm SC	SCR/DLN		PA = Power Augmentation
FPC - Hines Energy Complex	FL	draft permit	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 720 FO	2.5 ppm NG/ 10 ppm FO	SCR		SCONOx - $8,597/ton NOx;
FPL Turkey Point	FL	draft permit		4	4	GE 7FA (170 MW)	NG;FO	CC	8,760;500 FO	2.0 ppm NG/8.0 ppm FO	SCR	24-hr	SCR (3.5ppm) = $3,744/ton NOx; SCR (2.5 ppm) = $3,753/ton NOx
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	Oct-00	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	Oct-00	750	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	3.5 ppm NG; 42 ppm FO	SCR; WI		SCONOx - $17,490/ton NO_x; CatOx - $4,133/ton CO
GenPower Rincon	GA	Dec-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Effingham Power Co.	GA	Dec-00	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	Feb-01	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	3.5/9 ppm	SCR/DLN;		
CPV Terrapin, LLC	GA	Jun-01	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		
Savannah Electric and Power - Plant McIntosh	GA	04/17/2003	1,260	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	2.5 ppm NG; 6 ppm FO	SCR		After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2004

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
Live Oak Co., LLC	GA	applic. under review	600	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
Pecan Grove Generating	GA	applic. under review	550	2	2	SW 501FD (175 MW)	NG; FO	CC	8,760; 500 FO	3.5 ppm NG; 12. ppm FO	SCR		
Big River Power, LLC	GA	applic. under review	855	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	3.0 ppm NG; 8.0 ppm FO	SCR/DLN; WI		SCR - $5,075/ton NOx; CatOx - $4,712/ton CO
Kentucky Pioneer Energy	KY	Jun-01	540	2	0	GE 7FA (197 MW)	syngas/ NG	CC	8,760	15/20 ppm	Steam Injection	3-hr	
Duke Energy 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		
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	Apr-00	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	Aug-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr	
Lone Oak Energy Center	MS	Nov-01	800	3	3	F" Class (180 MW)	NG	CC	8,760	3.5 ppm	SCR		Base/PA/PA+DF/DF
Lee Power Partners	MS	Mar-01	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		
LSP-Pike Energy LLC	MS	Nov-00	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	4.5 ppm	SCR		
Magnolia Energy	MS	May-01	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	Jun-01	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	Jun-02	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	Dec-01	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	Nov-01	300	1	1	SW 501F (230 MW)	NG	CC	8,760	3.5 ppm	SCR		
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	Nov-99	1,110	2	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Modification of previous permit to switch 2 SC -> CC
Butler-Warner Generation Plant	NC	applic. under review	500	2	0	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
GenPower Earleys, LLC	NC	Jan-02	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
Mirant Gastonia	NC	05/28/2002	1,200	4	4	"F" Class (175 MW)	NG	CC	8,760	2.5/3.5 ppm	SCR		CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
Carolina Plant	NC	applic. under review	1,300	4	4	GE or SW (170 MW)	NG; FO	CC	8,760	2.5/3.5 ppm; 13/18 ppm	SCR		CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
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
Dominion Person, Inc.	NC	applic. under review	1,100	4	4	GE 7FA (172 MW)	NG; FO	CC	8,760; 500 FO	3.5 ppm; 15 ppm FO	SCR		
Forsyth Energy Project	NC	01/23/2004	812	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1200 FO	2.5/3.5 ppm NG; 13/18 ppm FO	SCR		CO Limit depends on CT model; NOx limit depends on operating history and 3.3/17 ppm trigger levels

Table B-2. Summary of BACT Determinations for NO_x for Combined Cycle CTs, 1999-2004

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
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		
Greenville Power Project	SC	applic. under review	810	3	3	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	3.5 ppm NG; 20 ppm FO	SCR		SCONOx - $18,300/ton NOx; CatOx - $5,800/ton CO; DB < 5,120 hr/yr
Jasper County Generating Facility	SC	05/28/2002	1,260	4	4	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	2.5 ppm NG; 7.5 ppm FO	SCR		SCONOx - $19,870/ton NOx; CatOx - $3,320/ton CO
Cherokee Falls Combined-Cycle Facility	SC	applic. under review	1,260	4	4	GE 7FA (173 MW)	NG, FO	CC	8,760; 720 FO	3.5 ppm NG; 12 ppm FO	SCR		SCONOx - $22,434/ton NOx; CatOx - $2,500/ton CO
Fork Shoals Energy, LLC	SC	applic. under review	1,150	2	2	"F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR		
Palmetto Energy Center	SC	applic. under review	970	3	3	GE 7FB (180 MW)	NG	CC	8,760	3.5 ppm	SCR		
Vanderbilt University	TN	May-00	10	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	DLN		
Memphis Generation LLC	TN	Apr-01	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	Feb-02	900	3	3	SW, GE 7FA or GE	NG; FO	CC	8,760	3.5 ppm NG; 42 ppm FO	DLN/SCR; WI		
TVA - Franklin	TN	draft permit	610	2	2	GE 7FA (195 MW)		CC	8,760	3.5 ppm	SCR		
Southern Power Co.	TN	applic. under review	1,940	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	3.5/9 ppm NG; 12/42 ppm FO	SCR/DLN: SCR/WI		

Abbreviations:

GE = General Electric
SW = Seimens Westinghouse

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

SC = Simple Cycle
CC = Combined Cycle

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

CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

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

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$1,759,493	$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	
Direct Installation Costs			
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
Indirect Costs			
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[TM] for the GE Frame 7FA in Combined Cycle Operation
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx[TM]	Basis of Cost Component
<u>Direct Annual Costs</u>			
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	
<u>Energy Costs</u>			
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/
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	
<u>Indirect Annual Costs</u>			
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, 1999-2004

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Alabama Power, Plant Barry	AL	Aug-99	200	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.060 lb/MMBtu	GCP		
Mobile Energy, LLC - Hog Bayou	AL	Jan-99	200	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	0.040 lb/MMBtu NG; 0.058 lb/mmBtu FO	GCP		
Alabama Power - Theodore Cogeneration Facility	AL	Mar-99	210	1	1	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Tenaska Alabama Partners	AL	Nov-99	846	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	32.9 ppm NG; 46.7 ppm NG/FO	GCP		
Georgia Power - Goat Rock	AL	Apr-00	-	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Georgia Power - Goat Rock (revision of above PSD application)	AL	Apr-01	2,460	8	8	GE 7FA (170 MW)	NG	CC	8,760	0.086 lb/MMBtu	GCP		
Alabama Electric Cooperative - Gantt Plant	AL	Mar-00	500	2	2	SW 501F (166 MW)	NG	CC	8,760	0.057 lb/MMBtu	GCP		
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 19 or 22 ppm	GCP		For NO_x and CO: SC w/GE or SC w/SW501F or CC (either)
Calpine Solutia - Decatur	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Calpine BP Amoco	AL	Jun-00	700	3	3	SW501F (180 MW)	NG	CC	8,760	0.117 lb/mmBtu	GCP		
Tenaska Alabama II Generating Station	AL	Feb-01	900	3	3	GE 7FA or Mitsubishi M501F	NG; FO	CC	8,760; 720 FO	0.037/0.047/0.089 lb/mmbtu (base/PA/FO) GE; 0.088/0.116/0.35 lb/mmbtu (base/PA/FO) - Mit	GCP		
Hillabee Energy Center	AL	Jan-01	700	2	2	SW501G (229 MW)	NG	CC	8,760	0.023/0.076 lb/mmBtu (w/PA and/or DB)	GCP		PA = Power Augmentation, DB= Duct Burning
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
GenPower - Kelly, LLC	AL	Jan-01	1,260	4	4	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 14 ppm (w/DB)	GCP		
Blount County Energy	AL	Jan-01	800	3	3	"F" Class (170 MW)	NG	CC	8,760	0.033 lb/mmBtu (77.7 lb/hr)	GCP		
Alabama Power - Autaugaville	AL	Jan-01	1,260	4	4	"F" Class (170 MW)	NG	CC	8,760	0.035 lb/mmBtu	GCP		
Tenaska Alabama IV Partners	AL	Oct-01	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	Oct-01	630	2	2	GE 7FA (170 MW)	NG	CC	8,760	15 ppm	GCP		SCONOx - $18760/ton NOX; CatOx- $5,006/ton CO
Duke Energy Dale, LLC	AL	Dec-01	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
Barton Shoals Energy, LLC	AL	Jul-02	1,200	4	4	GE 7FA (170 MW)	NG	CC	8,760	10 ppm (0.022 lb/mmbtu); 0.041 lb/mmbtu w/DB	GCP		EPA did not received application until 5/24/02
Kissimmee Utility Authority, Cane Island Power Park -Unit 3	FL	draft permit	250	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	12 ppm, 20 ppm w/ DB NG; 30 ppm FO	GCP		
Duke Energy - New Smyrna Beach	FL	draft permit	500	2	0	GE 7FA (165 MW)	NG	CC	8,760	12 ppm	GCP		
Lake Worth Generation	FL	Nov-99	244	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	12 ppm NG; 20 ppm FO	GCP		
Hines Energy (FPC)	FL	project dropped	500	2	0	SW 501F (165 MW)	NG; FO	CC	8,760; 1,000 FO	25 ppm NG - full load; 30 ppm FO	GCP		
Gulf Power - Smith Station	FL	Jul-00	340	2	2	GE 7FA (170 MW)	NG	CC	8,760	16 ppm w/ DB, 23 ppm w/ DB & SA	GCP		Netting out of PSD for NO_x and CO; SA = steam augmentation
Florida Power & Light - Sanford	FL	Sep-99	2,200	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	12 ppm NG; 20 ppm FO	GCP		Repowering, 4 units FO
Gainesville Regional Utilities, Kelly Generating Station	FL	Feb-00	133	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NO_x
Calpine Osprey Energy Center	FL	Jul-01	527	2	2	SW 501FD (170 MW)	NG	CC	8,760	10 ppm (17 ppm w/DB or PA)	GCP	24-hr Block	2,800 hr/yr - Power Aug. mode
Hines Energy (FPC)	FL	Jun-01	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 1,000 FO	16 ppm NG; 30 ppm FO	GCP	24-hr Block	SCONOx - $16,712/ton NO_x; CatOx - $2,130/ton CO
CPV - Gulfcoast	FL	Feb-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		SCONOx - no cost eval.; CatOx - $4,350/ton CO
TECO Gannon/Bayside	FL	Mar-01	1,728	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	7.2 ppm NG; 14.2 ppm FO	GCP		Repowering project: netting out of NO_x, CO, PM_{10} and SO_2 review (subject to VOC reveiw)
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		2 SC CT and 1 CC CT also capable of operating in SC mode.
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode.
Calpine Blue Heron Energy Center	FL	draft permit	1,080	4	4	SW 501F (170 MW)	NG	CC	8,760	10/15.6/38.5/50 ppm	GCP		base/duct burner/power aug./60-70% load; SCONOx - $9,982/ton NO_x; CatOx - $1,553/ton CO

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2004

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
Jacksonville Electric Authority - Brandy Branch (revision)	FL	Mar-02	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	May-02	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	Jan-02	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	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC); 12 ppm (CC w/PA); 8 ppm (CC)	GCP	24-hr	* 1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
CPV Pierce Power Generation Facility	FL	Aug-01	250	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA) ; 17 ppm FO (19 ppm 76-89% load, 26 ppm 50-75% load)	GCP	24-hr	PA limited to 2,000 hr/yr
Fort Pierce Repowering Project	FL	draft permit	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500	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)
CPV Cana Power Generation Facility	FL	01/17/2002	245	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	8 ppm NG (13 ppm w/PA) ; 17/19/26 ppm FO	GCP	24-hr	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load
FPL Martin	FL	04/16/2003	1,150	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 5000 FO/1,000; 500 FO	10 ppm NG/8 ppm NG (12 ppm w/PA); 15 ppm FO	GCP	24-hr	PA = Power Augmentation
FPL Manatee	FL	04/15/2003	1,150	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	10 ppm NG/8 ppm NG (12 ppm w/PA)	GCP	24-hr	PA = Power Augmentation
FPC - Hines Energy Complex	FL	09/19/2003	530	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760; 720 FO	10 ppm NG/20 ppm FO	GCP	24-hr	SCONOx - $8,597/ton NOx;
FPL Turkey Point	FL	draft permit		4	4	GE 7FA (170 MW)	NG;FO	CC	8,760;500 FO	4.1 ppm NG/7.6 ppm NG w/DB/8 ppm NG w/PA&DB/14ppm w/PK&DB; 8.0 ppm FO	GCP	24-hr	SCR (3.5ppm) = $3,744/ton NOx; SCR (2.5 ppm) = $3,753/ton NOx
Georgia Power - Wansley (Oglethorpe Power)	GA	Jul-00	2,280	8	8	GE 7FA (170 MW)	NG	CC	8,760	29.5 ppm/0.066 lb/MMBtu	GCP		
Duke Energy Murray, LLC	GA	Feb-01	1,240	4	4	GE 7FA (170 MW)	NG	CC	8,760	21.8 ppm	GCP		
Duke Energy Buffalo Creek, LLC	GA	Oct-00	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	Sep-01	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 Rincon	GA	Dec-00	528	2	2	GE 7FA (170 MW)	NG	CC	8,760	9 ppm/14 (w/DB) ppm	GCP		
Effingham Power Co.	GA	Dec-00	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	draft permit	1,550	6	4	F" Class	NG	CC/SC	8,760/2,500	10.6 ppm (25 ppm w/DB)	GCP		
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	
Savannah Electric and Power - Plant McIntosh	GA	04/17/2003	1,260	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	2.0 ppm	CatOx		After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)
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		
Pecan Grove Generating	GA	applic. under review	550	2	2	SW 501FD (175 MW)	NG; FO	CC	8,760; 500 FO	15;22.9;25;50 ppm (NG; NG w/DB;NG @70%; FO)	GCP		
Big River Power, LLC	GA	applic. under review	855	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 500 FO	19.2 ppm (w/DB)/9.0 ppm (w/o DB) NG; 20.o ppm FO	GCP		SCR - $5,075/ton NOx; CatOx - $4,712/ton CO
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		
Duke Energy Hinds, L.L.C.	MS	Apr-00	520	2	0	GE 7FA (170 MW)	NG	CC	8,760	20 ppm	GCP		

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2004

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
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	Apr-00	800	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm, 18 ppm w/ DB	GCP		
Cogentrix Energy, Caledonia Power Project	MS	Mar-01	800	3	3	GE 7FA (182 MW)	NG	CC	8,760	9 ppm	GCP		revised application to add SCR
GenPower - McAdams LLC	MS	Aug-00	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	Nov-01	800	3	3	F" Class (180 MW)	NG	CC	8,760	10/25/30/17 ppm	GCP		Base/PA/PA+DF/DF
Lee Power Partners	MS	Mar-01	1,000	4	4	F" Class (170 MW)	NG	CC	8,760	25 ppm	GCP		
LSP-Pike Energy LLC	MS	Nov-00	1,100	4	4	F" Class (170 MW)	NG	CC	8,760	33.1 ppm (0.15 lb/mmBTU)	GCP		
Magnolia Energy	MS	May-01	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	Jun-01	844	3	3	GE 7FA (170 MW)	NG	CC	8,760	18.36 ppm	GCP		SCONOx - $48,663/ton NO_x; CatOx - $3,550/ton CO
Crossroads Energy Center	MS	Jun-02	580	2	2	GE 7FA (170 MW)	NG	CC	8,760	10.4 ppm	GCP		SCONOx - $23,400/ton NO_x; CatOx - $11,039/ton CO
Choctaw Gas Generation, LLC	MS	Dec-01	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		
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
Mirant Gastonia	NC	05/28/2002	1,200	4	4	"F" Class (175 MW)	NG	CC	8,760	15 or 30 ppm	GCP	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
Carolina Plant	NC	applic. under review	1,300	4	4	GE or SW (170 MW)	NG; FO	CC	8,760	47 or 50 ppm	GCP	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level
Mountain Creek - Granville Energy Center	NC	applic. under review	911	3	3	GE 7FA (170 MW)	NG	CC	8,760	9 ppm (24.3 ppm w/DB)	GCP		SCONOx - $22,600/ton NOx; CatOx - $3,560ton CO
Dominion Person, Inc.	NC	applic. under review	1,100	4	4	GE 7FA (172 MW)	NG; FO	CC	8,760; 500 FO	9 ppm NG (20 ppm w/DB) 20 ppm FO	GCP		
Forsyth Energy Project	NC	01/03/2004	812	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 1200 FO	25.9 ppm NG (w/DB); 25.1 ppm FO (w/DB)	GCP	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3.3/17 ppm trigger levels
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		
Greenville Power Project	SC	applic. under review	810	3	3	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	12.3 ppm NG; 16.5 ppm FO	GCP		SCONOx - $18,300/ton NOx; CatOx - $5,800/ton CO; DB < 5,120 hr/yr
Jasper County Generating Facility	SC	05/28/2002	1,260	4	4	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	9 ppm NG (14 ppm w/DB); 20 ppm FO (22 ppm w/DB)	GCP		SCONOx - $19,870/ton NOx; CatOx - $3,320/ton CO
Cherokee Falls Combined-Cycle Facility	SC	applic. under review	1,260	4	4	GE 7FA (173 MW)	NG, FO	CC	8,760; 720 FO	0.063 lb/mmbtu NG; 0.069 lb/mmbtu FO	GCP		SCONOx - $22,434/ton NOx; CatOx - $2,500/ton CO
Fork Shoals Energy, LLC	SC	applic. under review	1,150	2	2	"F" Class (175 MW)	NG	CC	8,760	14 ppm (GE7FA/16 ppm (SW501F)	GCP	24-hr	

Table B-7. Summary of BACT Determinations for CO for Combined Cycle CTs, 1999-2004

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
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		
Southern Power Co.	TN	applic. under review	1,940	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	0.035 lb/mmbtu NG; 0.069 lb/mmbtu FO	GCP		

Abbreviations:
GE = General Electric
SW = Seimens Westinghouse
NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner
SC = Simple Cycle
CC = Combined Cycle
DLN = Dry-Low NOx
WI = Water Injection
SCR = Selective Catalytic Reduction
CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

Source: http://www.epa.gov/region4/air/permits/national_ct_list.xls (2001)

Table B-8. Direct and Indirect Capital Costs for CO Catalyst, GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
<u>Direct Capital Costs</u>		
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	
<u>Direct Installation Costs</u>		
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
<u>Indirect Costs</u>		
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

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

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 4 Project are required to be addressed at the PSD Class I area of the Chassahowitzka National Wildlife Area (NWA). The Chassahowitzka NWA is located approximately 118 km north-northwest of the facility site and is the only PSD Class I area located within 200 km of the project site.

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 Chassahowitzka NWA using the refined modeling approach from the IWAQM Phase 2 report for:

- Significant impact analysis,
- Regional haze analysis, and
- Total sulfur and nitrogen deposition.

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 5.7). At distances beyond 50 km, the ISCST3 model is considered to overpredict air quality impacts, because it is a steady-state model. At those distances, the CALPUFF model is recommended for use. 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 documents.

A regional haze analysis was performed to determine the affect that the facility's emissions will have on background regional haze levels at the 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 [$(NH_4)_2SO_4$] and ammonium nitrate (NH_4NO_3) concentrations. The change in visibility due to a source, estimated as a percentage, is then calculated based on the change from background data.

The following sections present the methods and assumptions used to assess the refined significant impact and regional haze analyses performed for the proposed project. The results of these analyses are presented in Sections 6.0 and 7.0 of the report.

C.3 MODEL SELECTION AND SETTINGS

The CALPUFF 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 5.5), 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 C-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 C-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 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 area. These receptors are the same as those used in the PSD Class I analysis performed for the PSD report.

C.5 METEOROLOGICAL DATA

C.5.1 REFINED ANALYSIS

CALMET was used to develop the gridded parameter fields required for the refined modeling analyses. The follow sections discuss the specific data used and processed in the CALMET model.

C.5.2 CALMET SETTINGS

The CALMET settings contained in Table C-3 were used for the refined modeling analysis.

C.5.3 MODELING DOMAIN

A rectangular modeling domain extending 352 km in the east-west (x) direction and 424 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 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 88 grid cells in the x-direction and 106 grid cells in the y-direction. The domain grid resolution is 4 km. The air modeling analysis was performed in the UTM coordinate system.

C.5.4 MESOSCALE MODEL – GENERATION 4 (MM4/5) 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 these datasets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and have been developed for the MM4 data for 1990 and the MM5 data for 1992 and 1996. The analysis used the MM4 and MM5 data to initialize the CALMET wind field. The 1990 MM4 and 1992 MM5 data have horizontal spacing of 80 km while the 1996 MM6 data has a spacing of 36 km. These data are used to simulate atmospheric variables within the modeling domain.

The MM4/5 subset domain consisted of a 9 by 9- cell rectangle, with 80 or 36 km grid resolution, extending from the MM4/5 grid points (49,9) to (57, 17). These data were processed to create a MM4.DAT or MM5.DAT file, for input to the CALMET model. The MM5 data for 1992 and 1996 were provided by the National Park Service and was processed in a similar manner as the MM4 data.

The MM4 and MM5 data sets 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 five NWS stations or Federal Aviation Administration (FAA) Flight Service stations for Gainesville, Tampa, Daytona Beach, Vero Beach, Fort Myers and Orlando. A summary of the surface station information and locations are presented in Table C-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 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 C-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 C-5.

C.5.8 GEOPHYSICAL DATA PROCESSING

The land-use and terrain information data were developed for the modeling domain and were converted into a GEO.DAT file format for input to CALMET. Terrain elevations for each grid cell of the modeling domain were obtained from Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data was extracted for the modeling domain grid using the utility extraction program TERREL. Land-use data were obtained from the USGS LULC grid-cell data, and were extracted using the utility programs CTGCOMP and CTGPROC. The scale for both the DEM and LULC files was 1:250,000.

Table C-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} or 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 deposition: compute dry and wet fluxes of nitrogen and sulfur emissions on an annual averaged basis and adjust concentrations using the molecular weight ratios provided in the FLAG document. Compute total sulfur and nitrogen deposition. 4. For significant impact analysis: use highest annual and highest short-term averaging time concentrations for SO_2, NOx, or PM_{10}.

[a] IWAQM Phase II report (12/98) and FLAG document (12/00)

Table C-2. CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, PM_{10}, and CO
Chemical Transformation	MESOPUFF II scheme
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
Model Processing	For haze: highest predicted 24-hour extinction change (%) for the year For deposition, predicted total annual averaged sulfur and nitrogen deposition and compare to FLM deposition analysis thresholds (DAT). For eastern PSD Class I areas, the DAT are 0.01 kg/ha/yr for both total sulfur and total nitrogen For significant impact analysis: highest predicted annual and highest short-term averaging time concentrations for SO_2, NO_x, and PM_{10}.
Background Values [a]	Ozone: 50 ppb; Ammonia: 1 ppb

[a] Recommended by the National Park Service.

Table C-3. General CALMET Settings, 1990, 1992, and 1996 Domains

Parameter	Setting
Horizontal Grid Dimensions	352 by 424 km, 4 km grid resolution
Vertical Grid	10 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	1990: MM4 data, 80-km resolution, 9 x 9 grid, used for wind field initialization 1992: MM5 data, 80-km resolution, 9 x 9 grid, used for wind field initialization 1996: MM5 data, 36-km resolution, 16 x 16 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

Table C-4. Surface and Upper Air Stations Used in the CALPUFF Analysis

Station Name	Station Symbol	WBAN Number	UTM Coordinates Easting (km)	Northing (km)	Zone	Anemometer Height (m)
Surface Stations						
Tampa	TPA	12842	349.20	3094.25	17	6.7
Daytona Beach	DAB	12834	495.14	3228.05	17	9.1
Orlando	ORL	12815	468.96	3146.88	17	10.1
Gainesville	GNV	12816	377.40	3284.12	17	6.7
Vero Beach	VER	12843	557.52	3058.36	17	6.7
Fort Myers	FMY	12835	413.65	2940.38	17	6.1
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; Zone 16 coordinate is 690.22 km.

8/3/04

Table C-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	3193.256	17
Lynne	85237	409.255	3230.295	17
Marineland	85391	479.193	3282.030	17
Melbourne WSO	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	470.174	2962.267	17
Parrish	86880	366.986	3054.394	17
Port Mayaca S L Canal	87293	538.044	2984.440	17
Saint Leo	87851	376.483	3135.086	17
St Lucie New Lock 1	87859	571.042	2999.353	17
St Petersburg	87886	339.608	3071.991	17
Tampa Wscmo AP	88788	348.478	3093.670	17
Venice	89176	357.593	2998.178	17
Venus	89184	467.266	3001.224	17
Vero Beach 4 W	89219	554.268	3056.498	17
West Palm Beach Int AP	89525	589.611	2951.627	17

BUILDING PARAMETER INPUT PROGRAM
(BPIP)

INPUT AND OUTPUT FILES

'D:\FPL Hines 4\bpip\hines4.bpv'

```
'ST'
'Meters'  1.00000000
'UTMN'  0.0000
7
'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
'HRSG4A'  1         0.000
   4          24.000
         -478.010         56.480
         -469.230         56.480
         -469.230         34.000
         -478.010         34.000
'HRSG4B'  1         0.000
   4          24.000
         -437.430         56.480
         -428.660         56.480
         -428.660         34.000
         -437.430         34.000
'FUEL'  1         0.000
   8          14.630
         -465.394         -1.959
         -455.531         -6.023
         -450.895        -15.886
         -455.531        -25.749
         -465.394        -30.395
         -475.268        -25.749
         -479.321        -15.886
         -475.268         -6.023
'FUEL'  1         0.000
   8          14.630
         -468.680        -32.890
         -461.560        -36.180
         -458.270        -43.860
         -461.560        -50.980
         -468.680        -54.270
```

```
        -476.360      -50.980
        -479.650      -43.860
        -476.360      -36.180
'ADMIN'  1       0.000
   4       5.180
        -576.700      -31.250
        -538.320      -31.250
        -538.320      -49.340
        -576.700      -49.340
2
'STCK1'      0.000       38.100      -473.667       29.000
'STCK2'      0.000       38.100      -432.519       29.000
```

BPIP (Dated: 95086)

DATE : 7/27/ 4
TIME : 14: 2:23
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 Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
STCK1	38.10	0.00	60.00	65.00
STCK2	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 : 7/27/ 4
TIME : 14: 2:23

D:\FPL Hines 3\bpip\hines3.bpv

BPIP output is in meters

SO BUILDHGT STCK1	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDHGT STCK1	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDHGT STCK1	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDHGT STCK1	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDHGT STCK1	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDHGT STCK1	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDWID STCK1	12.55	15.94	18.84	21.18	22.86	23.86
SO BUILDWID STCK1	24.12	23.66	22.48	23.66	24.13	23.86
SO BUILDWID STCK1	22.86	21.18	18.84	15.94	12.55	8.78
SO BUILDWID STCK1	12.55	15.94	18.84	21.18	22.86	23.86
SO BUILDWID STCK1	24.12	23.66	22.48	23.66	24.13	23.86
SO BUILDWID STCK1	22.86	21.18	18.84	15.94	12.55	8.78

SO BUILDHGT STCK2	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDHGT STCK2	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDHGT STCK2	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDHGT STCK2	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDHGT STCK2	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDHGT STCK2	24.00	24.00	24.00	24.00	24.00	24.00
SO BUILDWID STCK2	12.54	15.93	18.84	21.17	22.86	23.85
SO BUILDWID STCK2	24.12	23.66	22.48	23.66	24.12	23.86
SO BUILDWID STCK2	22.86	21.18	18.84	15.93	12.54	8.77
SO BUILDWID STCK2	12.54	15.93	18.84	21.17	22.86	23.85
SO BUILDWID STCK2	24.12	23.66	22.48	23.66	24.12	23.86
SO BUILDWID STCK2	22.86	21.18	18.84	15.93	12.54	8.77

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

Pollutant	Base Load 20°F	Base Load 59°F	Base Load 90°F(NG)/ 105°F (FO)	80% Load 20°F	80% Load 59°F	80% Load 90°F(NG)/ 105°F (FO)	60% (NG) /65% Load(FO) 20°F	60% (NG) /65% Load(FO) 59°F	60% (NG) /65% Load(FO) 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
SO_2	5.6	5.1	4.8	4.3	4.3	4.0	3.8	3.6	3.3
PM10	8.5	7.9	7.2	7.5	7.1	6.3	6.1	5.8	5.5
NO_x	25.0	23.1	21.2	20.6	19.1	17.7	16.8	15.9	14.6
CO	46.0	42.0	37.0	38.0	35.0	33.0	154.0	146.0	134.0
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
SO_2	105.60	97.13	86.00 #	85.60	79.36	71.03 ##	72.00	68.00	62.00
PM10	64.8	59.6	52.5	52.4	48.6	44.3	43.5	40.9	37.2
NO_x	116.9	109.4	96.7	96.6	89.4	80.0	81.2	76.0	69.3
CO	112.0	106.0	91.0	111.0	103.0	89.0	101.0	94.0	86.0

Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)

Pollutant	Averaging Time	Base Load 20°F	Base Load 59°F	Base Load 90°F(NG)/ 105°F (FO)	80% Load 20°F	80% Load 59°F	80% Load 90°F(NG)/ 105°F (FO)	60% (NG) /65% Load(FO) 20°F	60% (NG) /65% Load(FO) 59°F	60% (NG) /65% Load(FO) 90°F(NG)/ 105°F (FO)
Natural Gas										
Generic (10 g/s)	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	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	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	Annual	0.039	0.039	0.039	0.037	0.036	0.036	0.040	0.039	0.038
CO	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)	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	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	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	Annual	0.104	0.102	0.102	0.087	0.086	0.088	0.081	0.081	0.081
CO	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