Stanton A Combined Cycle
Title V Permit Application

October 24, 2003

Curtis H. Stanton Energy Center
Orange County
Orlando, Florida
FDEP File No: 0950137-002-AC

Prepared by:

GULF POWER
A SOUTHERN COMPANY

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: OUC/KUA/FMPA/Southern Company – Florida, LLC
2. Site Name: Curtis H. Stanton Energy Center
3. Facility Identification Number: 0950137
4. Facility Location... 5100 South Alafaya Trail
   Street Address or Other Locator:
   City: Orlando County: Orange Zip Code: 32831
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: G. Dwain Waters
2. Application Contact Mailing Address... One Energy Place
   Organization/Firm: Southern Company – Florida, LLC
   Street Address:
   City: Pensacola State: Florida Zip Code: 32520-0328
3. Application Contact Telephone Numbers...
   Telephone: (850) 444 - 6527 ext. Fax: (850) 444 - 6217
4. Application Contact Email Address: gdwaters@southernco.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Project Number(s):	0950137·005·AV
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

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

This application is to incorporate the new Combined Cycle Combustion Turbine units (Units 25 & 26) into the Stanton Energy Center Title V permit.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
25	Stanton Combined Cycle Unit A(N) Nominal 317 MW	N/A	N/A
26	Stanton Combined Cycle Unit A(S) Nominal 317 MW	N/A	N/A
27	Cooling Tower	N/A	N/A
28	Distillate Fuel Oil Storage Tank (1,680,000 gal)	N/A	N/A

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 :

2. Owner/Authorized Representative Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

3. Owner/Authorized Representative Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

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.

   Signature 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: Ronald H. Walston
   (This is an Alternative Responsible Official; see page 7 for Facility Responsible Official)

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):

   [X] 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...P. O. Box 781295
   Organization/Firm: Southern Company
   Street Address: 5100 South Alafaya Trail
   City: Orlando State: Florida Zip Code: 32878

4. Application Responsible Official Telephone Numbers...
   Telephone: (321) 235 - 2521 ext. Fax: (321) 235 - 2595

5. Application Responsible Official Email Address: rhwalsto@southernco.com

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.

   Ronald H. Walston — Signature

   10/20/03 — Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Thomas W. Davis
   Registration Number: 36777
2. Professional Engineer Mailing Address...
   Organization/Firm: Environmental Consulting & Technology, Inc.
   Street Address: 3701 Northwest 98th Street
   City: Gainesville State: Florida Zip Code: 32606-5004
3. Professional Engineer Telephone Numbers...
   Telephone: (352) 332 - 6230 ext. 351 Fax: (352) 332 - 6722
4. Professional Engineer Email Address: tdavis@ectinc.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 [X], 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.

Thomas W. Davis
Signature

10/25/03
Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates...		2. Facility Latitude/Longitude...	
Zone 17 East (km) 483.61 North (km) 3151.1		Latitude (DD/MM/SS) 28/29/17 Longitude (DD/MM/SS) 81/10/03	
3. Governmental Facility Code:	4. Facility Status Code:	5. Facility Major Group SIC Code:	6. Facility SIC(s):
4	A	49	4911

7. Facility Comment :
The purpose of this application is to incorporate the new combined cycle units, cooling tower and distillate oil storage tank into the Stanton Energy Center Title V Permit.

Facility Contact

1. Facility Contact Name: Ronald H. Walston

2. Facility Contact Mailing Address... P.O. Box 781295
Organization/Firm: Southern Company – Florida, LLC
Street Address: 500 Alafaya Trail
City: Orlando State: Florida Zip Code: 32878

3. Facility Contact Telephone Numbers:
Telephone: (231) 235- 2521 ext. Fax: (321) 235- 2595

4. Facility Contact Email Address: rhwalso@southernco.com

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: Frederick Haddad, Jr.

2. Facility Primary Responsible Official Mailing Address...500 South Orange Ave.
Organization/Firm: Orlando Utilities Commission
Street Address:
City: Orlando State: Florida Zip Code: 32808

3. Facility Primary Responsible Official Telephone Numbers...
Telephone: (407) 658-6444 - ext. 3770 Fax: (407) 236 - 9616

4. Facility Primary Responsible Official Email Address: fhaddad@ouc.com

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: a) Facility units currently exempt under NESHAPS. The cooling tower is not subject to a NESHAP because chromium-based chemical treatment is not used – the cooling tower is not a major source of HAPS. b) Stanton A is not major for HAPS but the Stanton Energy Center is a major source for HAPs thus we have included notice in this application. c) See PSD-FL-313 (PA81-14SA2) for alternative startup and shutdown emission limitations.	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOx	A	N
CO	A	N
PM/PM10	A	N
SO2	A	N
VOC	A	N
HAPS	A	N

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)
   [X] Attached, Document ID: Attachment C [ ] 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)
   [X] Attached, Document ID: Attachment D [ ] 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)
   [X] Attached, Document ID: Attachment L [ ] Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location:
   [ ] Attached, Document ID:_____ [ ] 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: Attachment J ☐ 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: Attachment A
   ☐ 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: Attachment U
   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: Attachment M ☐ Not Applicable

6. Requested Changes to Current Title V Air Operation Permit:
   ☒ Attached, Document ID: Attachment K ☐ 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.)

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section: One General Electric 7241 FA combustion turbine generator operating in combined cycle (CCCT) mode with one heat recovery steam generator (HRSG) @ nominal rating of 317 MW (includes 50% of the steam turbine). The unit is capable of firing natural gas and distillate fuel oil. Unit 25 shares a common steam turbine with Unit 26.

3. Emissions Unit Identification Number: 025

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	10/01/2001	4/28/03	49	[X] Yes [ ] No

9. Package Unit: Combined Cycle Combustion Turbine
   Manufacturer: General Electric Model Number: PG 7241 FA

10. Generator Nameplate Rating: 317 MW nominal rating

11. Emissions Unit Comment: The nominal 317 combined cycle combustion turbine is comprised of one combustion turbine, which exhausts through a heat recovery steam generator (HRSG) which, is used to power a steam turbine. Natural gas is the primary fuel ; low sulfur distillate duel oil is the back up fuel. Excess emissions resulting from startup, shutdown, duel switching or malfunction shall be permitted provided the best operational practices are adhered to and duration is minimized. See Alternative Startup/Shutdown limits in PSD permit.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

   Dry Low NOx (DLN) Combustor during Natural Gas firing – Burner technology to control NOx emissions. This technology uses a two-staged combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage.

   Water injection during Fuel Oil firing – for Oil firing cases only. This type of control injects water into the primary combustion zone with the fuel. The water serves to reduce NOx formation by reducing the peak flame temperature.

   Selective Catalytic Reduction (SCR) – for both natural gas and fuel oil operations. The SCR process combines vaporized ammonia with NOx in the presence of a catalyst to form nitrogen and water.

2. Control Device or Method Code(s): 205, 139

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: 2402 million Btu/hr (natural gas); 2068 mmbtu/hr (fuel oil)		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:		
For natural gas:	24 hours/day	7 days/week
	52 weeks/year	8760 hours/year
For fuel oil:	24 hours/day	7 days/week
	52 weeks/year	1000 hours/year

6. Operating Capacity/Schedule Comment:

Maximum Heat Input Rate in Field 1 based on:

a) Natural Gas: 19 °F, base load, with duct burners on. Performance Data Case 4 in Attachment G.

b) #2 Fuel Oil: 19 °F, base load. Performance Data Case 20 in Attachment G..

All cases of natural gas and oil firing were considered in these maximums.

Maximum hours of operation on natural gas in 8760 hrs/yr and 1000 hrs/yr for fuel oil.

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: 004	2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A 160 foot vertical cylindrical exhaust stack associated with the combustion turbine and heat recovery steam generator.		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: 160 feet	7. Exit Diameter: 19 feet
8. Exit Temperature: 287 °F	9. Actual Volumetric Flow Rate: 1,280,130 acfm	10. Water Vapor: N/A
11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 483.61 North (km): 3151.12	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) 28/29/17 Longitude (DD/MM/SS) 81/10/03	
15. Emission Point Comment: Field #8 based on distillate oil at 100% load @ 19° F. Field #9 based on distillate oil at 100% load @ 19° F. Stack temperature and flow rate will vary with fuel, load, ambient temperature, and use of optional evaporative cooling, duct burner firing and steam powr augmentation.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): Combustion turbine operating in combined cycle mode on natural gas. This unit is allowed to operate on natural gas for 8760 hours per year. The maximum heat input on natural gas for the CT/HRSG is 2402 mmbtu/hr (HHV). The maximum heat input for the duct burner is 542 mmbtu/hr (HHV) on natural gas.		
2. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned (all gaseous fuel)	
4. Maximum Hourly Rate: 2.35	5. Maximum Annual Rate: 20628.94	6. Estimated Annual Activity Factor:
7. Maximum Sulfur: 1.5 grains/100cc	8. Maximum % Ash:	9. Million Btu per SCC Unit: 1020
10. Segment Comment: Maximum Hourly Rate = $\frac{2402 \text{ mmbtu/hr}}{1020 \text{ mmbtu/mmscf}}$ = 2.35 mmscf/hr Maximum Annual Rate = $\frac{8760 \text{ hrs/year} \times 2402 \text{ mmbtu/hr}}{1020 \text{ mmbtu/mmscf}}$ = 20628.94 mmscf/yr		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): Combustion turbine operating in combined mode on No. @ distillate fuel oil. This unit is allowed to operate on No. 2 distillate fuel oil for 1000 hours/hr. The maximum heat input on No. 2 fuel oil is 2067.6 mmbtu/hr (HHV).		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand gallons burned (all liquid fuel)	
4. Maximum Hourly Rate: 14.87	5. Maximum Annual Rate: 14874.82	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: .05	8. Maximum % Ash: .01	9. Million Btu per SCC Unit: 139
10. Segment Comment: Maximum Hourly Rate = $\frac{2067.6 \text{ mmbtu/hr}}{139 \text{ mmbtu/thousand gallons}}$ = 14.87 thousand gallons/hr Maximum Annual Rate = $\frac{1000 \text{ hr/yr} \times 2067.6 \text{ mmbtu/hr}}{139 \text{ mmbtu/thousand gallons}}$ = 14874.82 thousand gallons/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
NOx	205	139	EL
CO			EL
PM/PM10			**NS**
SO2			EL
VOC			EL
HAPS *			NS
***Major only due to facility totals**			

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: NOx	2. Total Percent Efficiency of Control:

3. Potential Emissions: Natural Gas 30.38 lb/hour 132.58 tons/yr Fuel Oil 79.69 lb/hour 39.85 tons/yr Annual Operation 157.24 tons/yr	4. Synthetically Limited? [X] Yes [ ] No

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor: Reference:	7. Emissions Method Code: O

8. Calculation of Emissions:
Potential annual emissions(using highest hr emissions based on worst case ambient conditions) :
CCCT Natural Gas and duct firing (with Power Augmentation):
(30.38 lb/hr * 7760 hr/yr) + (29.42 lb/hr * 1000 hr/yr)/2000 = 132.58 tons/year

Fuel Oil Firing:
79.69 lb/hr * 1000 hr/yr/2000 lb/ton = 39.85 tons/year

Annual Operation on Natural Gas and Duct Firing plus Oil firing (with power augmentation):

$$\frac{(30.38 \text{ lb/hr} * 6760 \text{ hrs/yr}) + (79.69 \text{ lb/hr} * 1000 \text{ hr/yr}) + (29.42 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 157.24 \text{ tons per year}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Emission calculations based on manufacturer's guarantee.

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 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.5 ppmvd @ 15 % O2 for Natural Gas	4. Equivalent Allowable Emissions: 30.38 lb/hour 133.06 tons/year
5. Method of Compliance: CEMs on a 3 hour block average Record Keeping – hrs of operation per fuel type per 12 months. Stack testing – annually	
6. Allowable Emissions Comment (Description of Operating Method): During any 24 hour period in which an hour of start-up or shutdown occurs, the following alternative emissions limit apply on a 24 hour rolling average. 127 lb/hr for natural gas firing, 370 lb/hr for fuel oil firing; Prorated if co-fired.	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 10 ppmvd @ 15% O2 for fuel oil	4. Equivalent Allowable Emissions: 79.69 lb/hour 39.85 tons/year
5. Method of Compliance: CEMs on a 3 hour block average Record Keeping – hrs of operation per fuel type per 12 months. Stack testing	
6. Allowable Emissions Comment (Description of Operating Method): A total of 1000 hours per year of fuel oil firing is allowed. An alternative start-up and shutdown standard is applicable at 370 lbs/hr on 24 hour rolling average basis. This limit is prorated if co-fired.	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: PSD Permit (NSPS)	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: .1 lb/mmbtu	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Less than other applicable standards above.	
6. Allowable Emissions Comment (Description of Operating Method): Standard for HRSG Duct Burners.	

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: Natural Gas 142.51 lb/hour 448.12 tons/yr Fuel Oil 71.00 lb/hour 35.50 tons/yr Annual Operation 435.05 tons/yr	4. Synthetically Limited? [X] Yes [ ] No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: O

8. Calculation of Emissions:
Potential annual emissions(using highest hr emissions based on worst case ambient conditions) :

CCCT Natural Gas and duct firing (with Power Augmentation):
(97.13 lb/hr * 7760 hr/yr) + (142.51 lb/hr * 1000 hr/yr)/2000 = 448.12 tons/year

Fuel Oil Firing:
71.00 lb/hr * 1000 hr/yr/2000 lb/ton = 35.50 tons/year

Annual Operation on Natural Gas and Duct Firing plus Oil firing (with power augmentation):

$$\frac{(97.13 \text{ lb/hr} * 6760 \text{ hrs/yr}) + (71.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (142.51 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 435.05 \text{ tons per year}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Emission calculations based on manufacturer's guarantee.

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: N/A
3. Allowable Emissions and Units: 17 ppmvd @ 15% O2 on Natural Gas	4. Equivalent Allowable Emissions: 142.51 lb/hour 448.12 tons/year
5. Method of Compliance: CEMs on a 24 hour block average Record Keeping – hrs of operation per fuel type per 12 months. Stack testing – annually	
6. Allowable Emissions Comment (Description of Operating Method): During any 24 hour period in which an hour of start-up or shutdown occurs, the following alternative emissions limit apply on a 24 hour rolling average. 155 lb/hr for natural gas or fuel oil firing.	

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: 14 ppmvd @ 15% O2 for fuel oil	4. Equivalent Allowable Emissions: 71.0 lb/hour 35.5 tons/yr
5. Method of Compliance: CEMs on a 24 hour block average Record Keeping – hrs of operation per fuel type per 12 months. Stack testing	
6. Allowable Emissions Comment (Description of Operating Method): A total of 1000 hours per year of fuel oil firing is allowed. An alternative start-up and shutdown standard is applicable at 155 lbs/hr on 24 hour rolling average basis. .	

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: PM/PM10	2. Total Percent Efficiency of Control:

3. Potential Emissions:			4. Synthetically Limited?
Natural Gas	11.71 lb/hour	50.94 tons/yr	[X] Yes [ ] No
Fuel Oil	17.0 lb/hour	8.50 tons/yr	
Annual Operation		53.63 tons/yr	

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: O

8. Calculation of Emissions:
Potential annual emissions(using highest hr emissions based on worst case ambient conditions) :
CCCT Natural Gas and duct firing (with Power Augmentation):
(11.62 lb/hr * 7760 hr/yr) + (11.71 lb/hr * 1000 hr/yr)/2000 = 50.94 tons/year

Fuel Oil Firing:
17.00 lb/hr * 1000 hr/yr/2000 = 8.5 tons/year

Annual Operation on Natural Gas and Duct Firing plus Oil firing (with power augmentation):
$\frac{(11.62 \text{ lb/hr} * 6760 \text{ hrs/yr}) + (17.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (17.71 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}}$ = 53.63 tons per year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Emission calculations based on manufacturer's guarantee.

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: N/A
3. Allowable Emissions and Units: 10% Opacity VE Standard	4.Equivalent Allowable Emissions: 11.71 lb/hr 50.94 tons/year for gas firing
5. Method of Compliance: Fuel Monitoring Schedule Record Keeping – hrs of operation per fuel type per 12 months. VE Stack testing – annually	
6. Allowable Emissions Comment (Description of Operating Method): 7760 hours/yr of natural gas firing with Duct Burner and 1000 hours with Power Augmentation.	

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% Opacity VE Standard	4. Equivalent Allowable Emissions: 17.00 lb/hour 8.50 tons/year
5. Method of Compliance: Fuel Monitoring Schedule Record Keeping – hrs of operation per fuel type per 12 months. VE Stack testing	
6. Allowable Emissions Comment (Description of Operating Method): Emissions based on 1000 hours of operation per year	

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: SO2	2. Total Percent Efficiency of Control:

3. Potential Emissions: Natural Gas 3.50 lb/hour 15.28 tons/yr Fuel Oil 107.00 lb/hour 53.50 tons/yr Annual Operation 67.03 tons/yr	4. Synthetically Limited? [X] Yes [ ] No

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: O

8. Calculation of Emissions:
Potential annual emissions(using highest hr emissions based on worst case ambient conditions) :
CCCT Natural Gas and duct firing (with Power Augmentation):
(3.50 lb/hr * 7760 hr/yr) + (3.39 lb/hr * 1000 hr/yr)/2000 = 15.28 tons/year

Fuel Oil Firing:
107.00 lb/hr * 1000 hr/yr /2000 lb/ton= 53.50 tons/year

Annual Operation on Natural Gas and Duct Firing plus Oil firing (with power augmentation):
$\frac{(3.5 \text{ lb/hr} * 6760 \text{ hrs/yr}) + (107.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (3.39 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}}$ = 67.03 tons per year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Emission calculations based on manufacturer's guarantee.

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: N/A
3. Allowable Emissions and Units: 1.5 gr S/100scf fuel (gas)	4. Equivalent Allowable Emissions: 3.5 lb/hour 15.33 tons/year
5. Method of Compliance: Record Keeping – hrs of operation per fuel type per 12 months. Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method): 8760 hrs/yr of natural gas firing. Duct firing case is higher than power augmentation case therefore emissions assumed 8760 hours of CCCT operation with duct burner. PSD permit has not greater than 1.5 grains per 100 standard cubic foot.	

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 weight % S for fuel oil	4. Equivalent Allowable Emissions: 107.00 lb/hour 53.50 tons/year
5. Method of Compliance: Record Keeping – hrs of operation per fuel type per 12 months. Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method): A total of 1000 hours per year of fuel oil firing is allowed.. .	

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: Natural Gas 20.13 lb/hour 54.22 tons/yr Fuel Oil 8.00 lb/hour 4.00 tons/yr Annual Operation (see comment *) 52.53 tons/yr	4. Synthetically Limited? [x] Yes [ ] No

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: O

8. Calculation of Emissions:
Potential annual emissions(using highest hr emissions based on worst case ambient conditions) :
CCCT Natural Gas and duct firing (with Power Augmentation):
(11.38 lb/hr * 7760 hr/yr) + (20.13 lb/hr * 1000 hr/yr)/2000 = 54.22 tons/year

Fuel Oil Firing:
8.00 lb/hr * 1000 hr/yr/2000 lb/ton = 4.00 tons/year

Annual Operation on Natural Gas and Duct Firing plus Oil firing (with power augmentation):

$$\frac{(11.38 \text{ lb/hr} * 6760 \text{ hrs/yr}) + (8.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (20.13 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 52.53 \text{ tons per year}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
* Maximum potential to emit is 54.22 tons/yr as worst case scenario.
Emission calculations based on manufacturer's guarantee.

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: N/A
3. Allowable Emissions and Units: 6.3 ppmvd @ 15 % O2 for Natural Gas	4. Equivalent Allowable Emissions: 20.13 lb/hour 54.22 tons/year
5. Method of Compliance: Record Keeping – hrs of operation per fuel type per 12 months. Stack testing – initial test only	
6. Allowable Emissions Comment (Description of Operating Method): 8760 hour/yr of natural gas firing. PSD permit allowed 6.3 ppmvd @15% O2 with initial testing only.	

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: 2.7 ppmvd @ 15% O2 for fuel oil	4. Equivalent Allowable Emissions: 8.0 lb/hour 4.0tons/year
5. Method of Compliance: Record Keeping – hrs of operation per fuel type per 12 months. Stack testing – initial test only	
6. Allowable Emissions Comment (Description of Operating Method): A total of 1000 hours per year of fuel oil firing is allowed. PSD permit allowed 2.7 ppmvd @ 15% O2 with initial testing only.	

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: HAPS	2. Total Percent Efficiency of Control:

3. Potential Emissions:			4. Synthetically Limited?
Natural Gas	1.76 lb/hour	7.73 tons/yr	[x] Yes [ ] No
Fuel Oil	0.7 lb/hour	0.35 tons/yr	
Annual Operation		8.08 tons/yr	

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: 3

8. Calculation of Emissions:
Potential annual emissions

Major for HAPS only due to facility total for the Stanton Energy Center

Refer to Attachment N for full calculations.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Emission calculations based on manufacturer's heat input and AP-42 emission factors for indicidual HAPs.

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 1

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

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:
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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 2

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: Maximum Period of Excess Opacity Allowed: 6 min/hour	
4 Method of Compliance: - Stack testing (USEPA Reference Method 9) Annually - VE limit proposed in lieu of PM/PM10 pound per hour limit.	
5. Visible Emissions Comment: PSD Permit Limit	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: - Stack testing (USEPA Reference Method 9) annually	
5. Visible Emissions Comment: Florida Air Regulation Rule 62-296	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 3

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: Thermo Environmental Model Number: 42C	Serial Number: 42C-75965-381
5. Installation Date: 07/22/2003	6. Performance Specification Test Date: 07/24/03
7. Continuous Monitor Comment: NOx monitoring system is required under Part 75.	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: CO2	2. Pollutant(s): CO2
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: Siemens Model Number: Ultramat 6E	Serial Number: N1-ND-0882
5. Installation Date: 07/22/2003	6. Performance Specification Test Date: 07/24/03
7. Continuous Monitor Comment: CO2 monitoring required under Part 75.	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor _3_ of _3_

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: Siemens Model Number: Ultramat/Oxymat 6	Serial Number: P7-528
5. Installation Date: 07/22/2003	6. Performance Specification Test Date: 07/24/03
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

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

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)
   [X] Attached, Document ID: Attachment D [ ] 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)
   [X] Attached, Document ID: Attachment E [ ] 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)
   [X] Attached, Document ID: Attachment O [ ] 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)
   [X] Attached, Document ID: Attachment P [ ] 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 _____
   [X] Not Applicable

6. Compliance Demonstration Reports/Records
   [X] Attached, Document ID: Attachment T
   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
[X] Attached, Document ID: Attachment S [ ] Not Applicable (PSD Permit)

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: _____ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

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

5. Acid Rain Part Application
   - [X] Certificate of Representation (EPA Form No. 7610-1)
     - [ ] Copy Attached, Document ID:
   - [X] Acid Rain Part (Form No. 62-210.900(1)(a))
     - [X] Attached, Document ID: Attachment H
     - [ ] 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

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.)

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section: One General Electric 7241 FA combustion turbine generator operating in combined cycle (CCCT) mode with one heat recovery steam generator (HRSG) @ nominal rating of 317 MW (includes 50% of the steam turbine). The unit is capable of firing natural gas and distillate fuel oil. Unit 25 shares a common steam turbine with Unit 26.

3. Emissions Unit Identification Number: 026

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	10/01/2001	4/28/03	49	[X] Yes [ ] No

9. Package Unit: Combined Cycle Combustion Turbine
Manufacturer: General Electric Model Number: PG 7241 FA

10. Generator Nameplate Rating: 317 MW nominal rating

11. Emissions Unit Comment: The nominal 317 combined cycle combustion turbine is comprised of one combustion turbine, which exhausts through a heat recovery steam generator (HRSG) which, is used to power a steam turbine. Natural gas is the primary fuel ; low sulfur distillate duel oil is the back up fuel. Excess emissions resulting from startup, shutdown, duel switching or malfunction shall be permitted provided the best operational practices are adhered to and duration is minimized. See Alternative Startup/Shutdown limits in PSD permit.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

   Dry Low NOx (DLN) Combustor during Natural Gas firing – Burner technology to control NOx emissions. This technology uses a two-staged combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage.

   Water injection during Fuel Oil firing – for Oil firing cases only. This type of control injects water into the primary combustion zone with the fuel. The water serves to reduce NOx formation by reducing the peak flame temperature.

   Selective Catalytic Reduction (SCR) – for both natural gas and fuel oil operations. The SCR process combines vaporized ammonia with NOx in the presence of a catalyst to form nitrogen and water.

2. Control Device or Method Code(s): 205, 139

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: 2402 million Btu/hr (natural gas); 2068 mmbtu/hr (fuel oil)		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:		
For natural gas:	24 hours/day	7 days/week
	52 weeks/year	8760 hours/year
For fuel oil:	24 hours/day	7 days/week
	52 weeks/year	1000 hours/year

6. Operating Capacity/Schedule Comment:

Maximum Heat Input Rate in Field 1 based on:

a) Natural Gas: 19 °F, base load, with duct burners on. Performance Data Case 4 in Attachment G.

b) #2 Fuel Oil: 19 °F, base load. Performance Data Case 20 in Attachment G..

All cases of natural gas and oil firing were considered in these maximums.

Maximum hours of operation on natural gas in 8760 hrs/yr and 1000 hrs/yr for fuel oil.

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: 005	2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A 160 foot vertical cylindrical exhaust stack associated with the combustion turbine and heat recovery steam generator.		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: 160 feet	7. Exit Diameter: 19 feet
8. Exit Temperature: 287 °F	9. Actual Volumetric Flow Rate: 1,280,130 acfm	10. Water Vapor: N/A
11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 483.61 North (km): 3151.12	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) 28/29/17 Longitude (DD/MM/SS) 81/10/03	
15. Emission Point Comment: Field #8 based on distillate oil at 100% load @ 19° F. Field #9 based on distillate oil at 100% load @ 19° F. Stack temperature and flow rate will vary with fuel, load, ambient temperature, and use of optional evaporative cooling, duct burner firing and steam powr augmentation.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): Combustion turbine operating in combined cycle mode on natural gas. This unit is allowed to operate on natural gas for 8760 hours per year. The maximum heat input on natural gas for the CT/HRSG is 2402 mmbtu/hr (HHV). The maximum heat input for the duct burner is 542 mmbtu/hr (HHV) on natural gas.		
2. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned (all gaseous fuel)	
4. Maximum Hourly Rate: 2.35	5. Maximum Annual Rate: 20628.94	6. Estimated Annual Activity Factor:
7. Maximum Sulfur: 1.5 grains/100cc	8. Maximum % Ash:	9. Million Btu per SCC Unit: 1020
10. Segment Comment: Maximum Hourly Rate = $\frac{2402 \text{ mmbtu/hr}}{1020 \text{ mmbtu/mmscf}}$ = 2.35 mmscf/hr Maximum Annual Rate = $\frac{8760 \text{ hrs/year} \times 2402 \text{ mmbtu/hr}}{1020 \text{ mmbtu/mmscf}}$ = 20628.94 mmscf/yr		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): Combustion turbine operating in combined mode on No. @ distillate fuel oil. This unit is allowed to operate on No. 2 distillate fuel oil for 1000 hours/hr. The maximum heat input on No. 2 fuel oil is 2067.6 mmbtu/hr (HHV).		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand gallons burned (all liquid fuel)	
4. Maximum Hourly Rate: 14.87	5. Maximum Annual Rate: 14874.82	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: .05	8. Maximum % Ash: .01	9. Million Btu per SCC Unit: 139
10. Segment Comment: Maximum Hourly Rate = $\frac{2067.6 \text{ mmbtu/hr}}{139 \text{ mmbtu/thousand gallons}}$ = 14.87 thousand gallons/hr Maximum Annual Rate = $\frac{1000 \text{ hr/yr} \times 2067.6 \text{ mmbtu/hr}}{139 \text{ mmbtu/thousand gallons}}$ = 14874.82 thousand gallons/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
NOx	205	139	EL
CO			EL
PM/PM10			**NS**
SO2			EL
VOC			EL
HAPS *			NS
***Major only due to the facility totals.**			

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: NOx	2. Total Percent Efficiency of Control:

3. Potential Emissions:			4. Synthetically Limited?
Natural Gas	30.38 lb/hour	132.58 tons/yr	[X] Yes [ ] No
Fuel Oil	79.69 lb/hour	39.85 tons/yr	
Annual Operation		157.24 tons/yr	

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor:	7. Emissions Method Code:
Reference:	O

8. Calculation of Emissions:
Potential annual emissions(using highest hr emissions based on worst case ambient conditions) :
CCCT Natural Gas and duct firing (with Power Augmentation):
(30.38 lb/hr * 7760 hr/yr) + (29.42 lb/hr * 1000 hr/yr)/2000 = 132.58 tons/year

Fuel Oil Firing:
79.69 lb/hr * 1000 hr/yr/2000 lb/ton = 39.85 tons/year

Annual Operation on Natural Gas and Duct Firing plus Oil firing (with power augmentation):
$\frac{(30.38 \text{ lb/hr} * 6760 \text{ hrs/yr}) + (79.69 \text{ lb/hr} * 1000 \text{ hr/yr}) + (29.42 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}}$ = 157.24 tons per year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Emission calculations based on manufacturer's guarantee.

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 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.5 ppmvd @ 15 % O2 for Natural Gas	4. Equivalent Allowable Emissions: 30.38 lb/hour 133.06 tons/year
5. Method of Compliance: CEMs on a 3 hour block average Record Keeping – hrs of operation per fuel type per 12 months. Stack testing – annually	
6. Allowable Emissions Comment (Description of Operating Method): During any 24 hour period in which an hour of start-up or shutdown occurs, the following alternative emissions limit apply on a 24 hour rolling average. 127 lb/hr for natural gas firing, 370 lb/hr for fuel oil firing; Prorated if co-fired.	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 10 ppmvd @ 15% O2 for fuel oil	4. Equivalent Allowable Emissions: 79.69 lb/hour 39.85 tons/year
5. Method of Compliance: CEMs on a 3 hour block average Record Keeping – hrs of operation per fuel type per 12 months. Stack testing	
6. Allowable Emissions Comment (Description of Operating Method): A total of 1000 hours per year of fuel oil firing is allowed. An alternative start-up and shutdown standard is applicable at 370 lbs/hr on 24 hour rolling average basis. This limit is prorated if co-fired.	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: PSD Permit (NSPS)	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: .1 lb/mmbtu	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Less than other applicable standards above.	
6. Allowable Emissions Comment (Description of Operating Method): Standard for HRSG Duct Burners.	

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: Natural Gas 142.51 lb/hour 448.12 tons/yr Fuel Oil 71.00 lb/hour 35.50 tons/yr Annual Operation 435.05 tons/yr	4. Synthetically Limited? [X] Yes [ ] No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Manufacturer	7. Emissions Method Code: O

8. Calculation of Emissions:
Potential annual emissions(using highest hr emissions based on worst case ambient conditions) :

CCCT Natural Gas and duct firing (with Power Augmentation):
(97.13 lb/hr * 7760 hr/yr) + (142.51 lb/hr * 1000 hr/yr)/2000 = 448.12 tons/year

Fuel Oil Firing:
71.00 lb/hr * 1000 hr/yr/2000 lb/ton = 35.50 tons/year

Annual Operation on Natural Gas and Duct Firing plus Oil firing (with power augmentation):

$$\frac{(97.13 \text{ lb/hr} * 6760 \text{ hrs/yr}) + (71.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (142.51 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 435.05 \text{ tons per year}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Emission calculations based on manufacturer's guarantee.

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: N/A
3. Allowable Emissions and Units: 17 ppmvd @ 15% O2 on Natural Gas	4. Equivalent Allowable Emissions: 142.51 lb/hour 448.12 tons/year
5. Method of Compliance: CEMs on a 24 hour block average Record Keeping – hrs of operation per fuel type per 12 months. Stack testing – annually	
6. Allowable Emissions Comment (Description of Operating Method): During any 24 hour period in which an hour of start-up or shutdown occurs, the following alternative emissions limit apply on a 24 hour rolling average. 155 lb/hr for natural gas or fuel oil firing.	

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: 14 ppmvd @ 15% O2 for fuel oil	4. Equivalent Allowable Emissions: 71.0 lb/hour 35.5 tons/yr
5. Method of Compliance: CEMs on a 24 hour block average Record Keeping – hrs of operation per fuel type per 12 months. Stack testing	
6. Allowable Emissions Comment (Description of Operating Method): A total of 1000 hours per year of fuel oil firing is allowed. An alternative start-up and shutdown standard is applicable at 155 lbs/hr on 24 hour rolling average basis. .	

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: PM/PM10

2. Total Percent Efficiency of Control:

3. Potential Emissions:

Natural Gas	11.71 lb/hour	50.94 tons/yr
Fuel Oil	17.0 lb/hour	8.50 tons/yr
Annual Operation		53.63 tons/yr

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor:
Reference: Manufacturer

7. Emissions Method Code:
O

8. Calculation of Emissions:
Potential annual emissions(using highest hr emissions based on worst case ambient conditions) :
CCCT Natural Gas and duct firing (with Power Augmentation):
(11.62 lb/hr * 7760 hr/yr) + (11.71 lb/hr * 1000 hr/yr)/2000 = 50.94 tons/year

Fuel Oil Firing:
17.00 lb/hr * 1000 hr/yr/2000 = 8.5 tons/year

Annual Operation on Natural Gas and Duct Firing plus Oil firing (with power augmentation):
$\frac{(11.62 \text{ lb/hr} * 6760 \text{ hrs/yr}) + (17.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (17.71 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}}$ = 53.63 tons per year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Emission calculations based on manufacturer's guarantee.

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: N/A
3. Allowable Emissions and Units: 10% Opacity VE Standard	4.Equivalent Allowable Emissions: 11.71 lb/hr 50.94 tons/year for gas firing
5. Method of Compliance: Fuel Monitoring Schedule Record Keeping – hrs of operation per fuel type per 12 months. VE Stack testing – annually	
6. Allowable Emissions Comment (Description of Operating Method): 7760 hours/yr of natural gas firing with Duct Burner and 1000 hours with Power Augmentation.	

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% Opacity VE Standard	4. Equivalent Allowable Emissions: 17.00 lb/hour 8.50 tons/year
5. Method of Compliance: Fuel Monitoring Schedule Record Keeping – hrs of operation per fuel type per 12 months. VE Stack testing	
6. Allowable Emissions Comment (Description of Operating Method): Emissions based on 1000 hours of operation per year	

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: SO2	2. Total Percent Efficiency of Control:

3. Potential Emissions:			4. Synthetically Limited?
Natural Gas	3.50 lb/hour	15.28 tons/yr	[X] Yes [ ] No
Fuel Oil	107.00 lb/hour	53.50 tons/yr	
Annual Operation		67.03 tons/yr	

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor:	7. Emissions Method Code:
Reference: Manufacturer	O

8. Calculation of Emissions:
Potential annual emissions(using highest hr emissions based on worst case ambient conditions) :
CCCT Natural Gas and duct firing (with Power Augmentation):
(3.50 lb/hr * 7760 hr/yr) + (3.39 lb/hr * 1000 hr/yr)/2000 = 15.28 tons/year

Fuel Oil Firing:
107.00 lb/hr * 1000 hr/yr /2000 lb/ton= 53.50 tons/year

Annual Operation on Natural Gas and Duct Firing plus Oil firing (with power augmentation):

$$\frac{(3.5 \text{ lb/hr} * 6760 \text{ hrs/yr}) + (107.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (3.39 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 67.03 \text{ tons per year}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Emission calculations based on manufacturer's guarantee.

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: N/A
3. Allowable Emissions and Units: 1.5 gr S/100scf fuel (gas)	4. Equivalent Allowable Emissions: 3.5 lb/hour 15.33 tons/year
5. Method of Compliance: Record Keeping – hrs of operation per fuel type per 12 months. Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method): 8760 hrs/yr of natural gas firing. Duct firing case is higher than power augmentation case therefore emissions assumed 8760 hours of CCCT operation with duct burner. PSD permit has not greater than 1.5 grains per 100 standard cubic foot.	

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 weight % S for fuel oil	4. Equivalent Allowable Emissions: 107.00 lb/hour 53.50 tons/year
5. Method of Compliance: Record Keeping – hrs of operation per fuel type per 12 months. Fuel Monitoring Schedule	
6. Allowable Emissions Comment (Description of Operating Method): A total of 1000 hours per year of fuel oil firing is allowed.. .	

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:			4. Synthetically Limited?
Natural Gas	20.13 lb/hour	54.22 tons/yr	[X] Yes [ ] No
Fuel Oil	8.00 lb/hour	4.00 tons/yr	
Annual Operation (see comment *)		52.53 tons/yr	

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor:	7. Emissions Method Code:
Reference: Manufacturer	O

8. Calculation of Emissions:
Potential annual emissions(using highest hr emissions based on worst case ambient conditions) :
CCCT Natural Gas and duct firing (with Power Augmentation):
(11.38 lb/hr * 7760 hr/yr) + (20.13 lb/hr * 1000 hr/yr)/2000 = 54.22 tons/year

Fuel Oil Firing:
8.00 lb/hr * 1000 hr/yr/2000 lb/ton = 4.00 tons/year

Annual Operation on Natural Gas and Duct Firing plus Oil firing (with power augmentation):

$$\frac{(11.38 \text{ lb/hr} * 6760 \text{ hrs/yr}) + (8.00 \text{ lb/hr} * 1000 \text{ hr/yr}) + (20.13 \text{ lb/hr} * 1000 \text{ hr/yr})}{2000 \text{ lb/ton}} = 52.53 \text{ tons per year}$$

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
* Maximum potential to emit is 54.22 tons/yr as worst case scenario.
Emission calculations based on manufacturer's guarantee.

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: N/A
3. Allowable Emissions and Units: 6.3 ppmvd @ 15 % O2 for Natural Gas	4. Equivalent Allowable Emissions: 20.13 lb/hour 54.22 tons/year
5. Method of Compliance: Record Keeping – hrs of operation per fuel type per 12 months. Stack testing – initial test only	
6. Allowable Emissions Comment (Description of Operating Method): 8760 hour/yr of natural gas firing. PSD permit allowed 6.3 ppmvd @15% O2 with initial testing only.	

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: 2.7 ppmvd @ 15% O2 for fuel oil	4. Equivalent Allowable Emissions: 8.0 lb/hour 4.0tons/year
5. Method of Compliance: Record Keeping – hrs of operation per fuel type per 12 months. Stack testing – initial test only	
6. Allowable Emissions Comment (Description of Operating Method): A total of 1000 hours per year of fuel oil firing is allowed. PSD permit allowed 2.7 ppmvd @ 15% O2 with initial testing only.	

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: HAPS	2. Total Percent Efficiency of Control:

3. Potential Emissions:			4. Synthetically Limited?
Natural Gas	1.76 lb/hour	7.73 tons/yr	[X] Yes [ ] No
Fuel Oil	0.7 lb/hour	0.35 tons/yr	
Annual Operation		8.08 tons/yr	

5. Range of Estimated Fugitive Emissions (as applicable):
to tons/year

6. Emission Factor:	7. Emissions Method Code:
Reference: Manufacturer	3

8. Calculation of Emissions:
Potential annual emissions

Major for HAPS only due to facility total for the Stanton Energy Center

Refer to Attachment N for full calculations.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Emission calculations based on manufacturer's heat input and AP-42 emission factors for indicidual HAPs.

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 1

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

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:
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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 2

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: Maximum Period of Excess Opacity Allowed: 6 min/hour	
4 Method of Compliance: - Stack testing (USEPA Reference Method 9) Annually - VE limit proposed in lieu of PM/PM10 pound per hour limit.	
5. Visible Emissions Comment: PSD Permit Limit	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: - Stack testing (USEPA Reference Method 9) annually	
5. Visible Emissions Comment: Florida Air Regulation Rule 62-296	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 3

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: Thermo Environmental Model Number: 42C	Serial Number: 42C-73000-372
5. Installation Date: 07/29/2003	6. Performance Specification Test Date: 07//31/03
7. Continuous Monitor Comment: NOx monitoring system is required under Part 75.	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: CO2	2. Pollutant(s): CO2
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: Siemens Model Number: Ultramat 6E	Serial Number: N1-ND-0871
5. Installation Date: 07/29/2003	6. Performance Specification Test Date: 07/31/03
7. Continuous Monitor Comment: CO2 monitoring required under Part 75.	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor 3 of 3

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: Siemens Model Number: Ultramat/Oxymat 6	Serial Number: P7-529
5. Installation Date: 07/29/2003	6. Performance Specification Test Date: 07/31/03
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

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

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)
   [X] Attached, Document ID: Attachment D [ ] 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)
   [X] Attached, Document ID: Attachment E [ ] 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)
   [X] Attached, Document ID: Attachment O [ ] 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)
   [X] Attached, Document ID: Attachment P [ ] 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 _____
   [X] Not Applicable

6. Compliance Demonstration Reports/Records
   [X] Attached, Document ID: Attachment T
   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
[X] Attached, Document ID: Attachment S [ ] Not Applicable (PSD Permit)

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: _____ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

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

5. Acid Rain Part Application
   - [X] Certificate of Representation (EPA Form No. 7610-1)
     - [ ] Copy Attached, Document ID:
   - [X] Acid Rain Part (Form No. 62-210.900(1)(a))
     - [X] Attached, Document ID: Attachment H
     - [ ] 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

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:
10 cell linear mechanical draft cooling tower equipped with drift eliminators for control of PM/PM10.

3. Emissions Unit Identification Number: 027

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	10/01/01	04/03/03	49	☐ Yes ☒ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

   Drift eliminators

2. Control Device or Method Code(s): 015

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: 125,000 gal/min	
2. Maximum Production Rate: N/A	
3. Maximum Heat Input Rate: million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	7 days/week
52 weeks/year	8760 hours/year
6. Operating Capacity/Schedule Comment: Maximum process rate (Field 1) is the cooling tower recirculation rate.	

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: 006	2. Emission Point Type Code: 3	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Cooling tower consists of 10 cells.		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: 44.7 feet	7. Exit Diameter: 34 feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: N/A
11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: Cooling tower consists of 10 cells with 10 individual exhaust fans. Stack height and diameter provided in Fields 6 & 7 are for each cell. Exhaust volume and temperature will vary with ambient temperatures.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC): 3-85-001-01	3. SCC Units: million gallons throughput	
4. Maximum Hourly Rate: 7.5	5. Maximum Annual Rate: 65,700	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

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

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment __ of __

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

Segment Description and Rate: Segment __ of __

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

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/PM10	015		NS

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/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 4.6 lb/hour 20.3 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 4.6 Reference: AP-42, Section 13.4	7. Emissions Method Code: 3

8. Calculation of Emissions:

(125,000 gal/min) * (0.002 gal/100gal) * (3704 lb PM/10^6 lb water) * (8.345 lb/gal water) * (60 min/hr) = 4.6 lb/hr

(4.6 lb/hr) * (8760 hr/yr) * 1 ton/2000 lb) = 20.3 tons/yr PM/PM10

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

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 1

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):	

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):	

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 ___ 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:	

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 ___ of ___

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

Continuous Monitoring System: Continuous Monitor ___ of ___

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

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)
   [X] Attached, Document ID: Attachment D [ ] 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: _____ [ ] 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)
   [X] Attached, Document ID: Attachment S [ ] 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 _____
   [X] 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 _____
   [X] Not Applicable

6. Compliance Demonstration Reports/Records
   [X] Attached, Document ID: Attachment T
   Test Date(s)/Pollutant(s) Tested: Certification Statement
   [ ] 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
[X] Attached, Document ID: Attachment S [ ] Not Applicable (PSD Permit)

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: _____ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☒ Attached, Document ID: Attachment A
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

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.)

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   No. 2 Distillate Fuel Oil Storage Tank (1,680,000 gallons)

3. Emissions Unit Identification Number: 028

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	10/01/2001	04/28/03	49	[ ] Yes [X] No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment: This distillate fuel oil storage tank (1,680,000 gallons) is reported as an emission unit because it is subject to regulations based on the emissions guidelines of the New Source Performance Standards 40 CFR 60, Subpart Kb.

The tank is a vertical fixed roof design.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	28800 thousand gallons per year
2. Maximum Production Rate:	
3. Maximum Heat Input Rate:	million Btu/hr
4. Maximum Incineration Rate:	pounds/hr tons/day
5. Requested Maximum Operating Schedule:	
24 hours/day	7 days/week
52 weeks/year	8760 hours/year

6. Operating Capacity/Schedule Comment:

The maximum throughput rate corresponds to the use of No. 2 distillate fuel oil for 1000 hours of operation per year.

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: 007	2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof.		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: There are two types of emissions associated with the breather valve: Storage Loss and Working Loss		
5. Discharge Type Code:	6. Stack Height: 0 feet	7. Exit Diameter: 0 feet
8. Exit Temperature: 70 °F	9. Actual Volumetric Flow Rate: 0 acfm	10. Water Vapor: N/A %
11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: 40 feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: Additional information in reference to comments in Field #4 : Storage Loss : Emissions resulting from the explusion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barametric pressure. (Also known as standing loss). Working Loss : Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): Storage Loss : Emissions resulting from eht explusion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barametric pressure. (Also known as standing loss).		
2. Source Classification Code (SCC): 4-03-010-19	3. SCC Units: Thousand Gallons Stored	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor: 1680
7. Maximum % Sulfur: .05	8. Maximum % Ash: .01	9. Million Btu per SCC Unit: 139
10. Segment Comment: (1,680,000 gallons stored)/1000 gallons = 1680 capacity		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): Working Loss : Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.		
2. Source Classification Code (SCC): 4-03-010-21	3. SCC Units: Thousand Gallons Throughput	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: 28800	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: .05	8. Maximum % Ash: .01	9. Million Btu per SCC Unit: 139
10. Segment Comment: (28800000 gallons of fuel oil consumed by the turbines per yr)/1000 gallons = 28800 gal/year		

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
VOC			**NS**

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: lb/hour ..77 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: AP-42 EPA Tanks Program	7. Emissions Method Code: EPA Tanks Program
8. Calculation of Emissions: A detail emission estimate using EPA's Tanks Program is Attached as Attachment I.	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

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 __ of ___

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: As specified in 40 CFR 60.11(a) and (b), Subpart Kb	
6. Allowable Emissions Comment (Description of Operating Method): Rule: 40 CFR 60.11 (b) Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels for which construction, reconstruction or modification commenced after July 23, 1994.	

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):	

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 __ 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:	

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 ___ of ___

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

Continuous Monitoring System: Continuous Monitor ___ of ___

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

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)
   [X] Attached, Document ID: Attachment D [ ] 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)
   [X] Attached, Document ID: Attachment E [X] 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)
   [X] Attached, Document ID: NA [ ] 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)
   [X] Attached, Document ID: NA [ ] 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 _____
   [X] 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: _____
   _____
   [X] 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
[X] Attached, Document ID: Attachment S [ ] Not Applicable

EMISSIONS UNIT INFORMATION
Section [4] of [4]

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: _____ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☒ Attached, Document ID: Attachment A
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

Attachment A
Applicable Regulations

Title V Core List Effective: 03/01/02

[**Note:** The Title V Core List is meant to simplify the completion of the "List of Applicable Regulations" for DEP Form No. 62-210.900(1), Application for Air Permit - Long Form. The Title V Core List is a list of rules to which all Title V Sources are presumptively subject. The Title V Core List may be referenced in its entirety, or with specific exceptions. The Department may periodically update the Title V Core List.]

Federal: ***(description)***

40 CFR 61, Subpart M: NESHAP for Asbestos.

40 CFR 82: Protection of Stratospheric Ozone.
40 CFR 82, Subpart B: Servicing of Motor Vehicle Air Conditioners (MVAC).
40 CFR 82, Subpart F: Recycling and Emissions Reduction.

State: ***(description)***

CHAPTER 62-4, F.A.C.: PERMITS, effective 06-01-01

62-4.030, F.A.C.: General Prohibition.
62-4.040, F.A.C.: Exemptions.
62-4.050, F.A.C.: Procedure to Obtain Permits; Application.
62-4.060, F.A.C.: Consultation.
62-4.070, F.A.C.: Standards for Issuing or Denying Permits; Issuance; Denial.
62-4.080, F.A.C.: Modification of Permit Conditions.
62-4.090, F.A.C.: Renewals.
62-4.100, F.A.C.: Suspension and Revocation.
62-4.110, F.A.C.: Financial Responsibility.
62-4.120, F.A.C.: Transfer of Permits.
62-4.130, F.A.C.: Plant Operation - Problems.
62-4.150, F.A.C.: Review.
62-4.160, F.A.C.: Permit Conditions.
62-4.210, F.A.C.: Construction Permits.
62-4.220, F.A.C.: Operation Permit for New Sources.

CHAPTER 62-210, F.A.C.: STATIONARY SOURCES - GENERAL REQUIREMENTS, effective 06-21-01

62-210.300, F.A.C.: Permits Required.
62-210.300(1), F.A.C.: Air Construction Permits.
62-210.300(2), F.A.C.: Air Operation Permits.
62-210.300(3), F.A.C.: Exemptions.
62-210.300(5), F.A.C.: Notification of Startup.
62-210.300(6), F.A.C.: Emissions Unit Reclassification.
62-210.300(7), F.A.C.: Transfer of Air Permits.

62-210.350, F.A.C.: Public Notice and Comment.
62-210.350(1), F.A.C.: Public Notice of Proposed Agency Action.
62-210.350(2), F.A.C.: Additional Public Notice Requirements for Emissions Units Subject to Prevention of Significant Deterioration or Nonattainment-Area Preconstruction Review.
62-210.350(3), F.A.C.: Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources.

62-210.360, F.A.C.: Administrative Permit Corrections.
62-210.370(3), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility.
62-210.400, F.A.C.: Emission Estimates.
62-210.650, F.A.C.: Circumvention.
62-210.700, F.A.C.: Excess Emissions.

62-210.900, F.A.C.: Forms and Instructions.
62-210.900(1), F.A.C.: Application for Air Permit – Title V Source, Form and Instructions.
62-210.900(5), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions.
62-210.900(7), F.A.C.: Application for Transfer of Air Permit – Title V and Non-Title V Source.

CHAPTER 62-212, F.A.C.: STATIONARY SOURCES - PRECONSTRUCTION REVIEW, effective 08-17-00

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 04-16-01

62-213.205, F.A.C.: Annual Emissions Fee.
62-213.400, F.A.C.: Permits and Permit Revisions Required.
62-213.410, F.A.C.: Changes Without Permit Revision.
62-213.412, F.A.C.: Immediate Implementation Pending Revision Process.
62-213.415, F.A.C.: Trading of Emissions Within a Source.
62-213.420, F.A.C.: Permit Applications.
62-213.430, F.A.C.: Permit Issuance, Renewal, and Revision.
62-213.440, F.A.C.: Permit Content.
62-213.450, F.A.C.: Permit Review by EPA and Affected States
62-213.460, F.A.C.: Permit Shield.

62-213.900, F.A.C.: Forms and Instructions.
62-213.900(1), F.A.C.: Major Air Pollution Source Annual Emissions Fee Form.
62-213.900(7), F.A.C.: Statement of Compliance Form.

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 03-02-99

62-296.320(4)(c), F.A.C.: Unconfined Emissions of Particulate Matter.

62-296.320(2), F.A.C.: Objectionable Odor Prohibited.

CHAPTER 62-297, F.A.C.: STATIONARY SOURCES - EMISSIONS MONITORING, effective 03-02-99

62-297.310, F.A.C.: General Test Requirements.
62-297.330, F.A.C.: Applicable Test Procedures.
62-297.340, F.A.C.: Frequency of Compliance Tests.
62-297.345, F.A.C.: Stack Sampling Facilities Provided by the Owner of an Emissions Unit.
62-297.350, F.A.C.: Determination of Process Variables.
62-297.570, F.A.C.: Test Report.
62-297.620, F.A.C.: Exceptions and Approval of Alternate Procedures and Requirements.

Miscellaneous:

CHAPTER 28-106, F.A.C.: Decisions Determining Substantial Interests
CHAPTER 62-110, F.A.C.: Exception to the Uniform Rules of Procedure, effective 07-01-98
CHAPTER 62-256, F.A.C.: Open Burning and Frost Protection Fires, effective 11-30-94
CHAPTER 62-257, F.A.C.: Asbestos Notification and Fee, effective 02-09-99
CHAPTER 62-281, F.A.C.: Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling, effective 09-10-96

List of Applicable Regulations

FDEP Title V Core List (effective 3/25/95) incorporated by reference

40 CFR Part 60, Subpart A – Standards of Performance for New Stationary Sources

40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines

Part 70 – State Operating Permit Programs

Section 70.1 - Program Overview

Section 70.2 - Definitions

Section 70.3 - Applicability

Section 70.4 - State Program Submittals and Transition

Section 70.5 - Permit Applications

Section 70.6 - Permit Content

Section 70.7 - Permit Issuance, Renewal, Reopenings, and Revisions

Section 70.8 – Permit Review by the EPA and Affected States

Section 70.9 – Fee Determination and Certification

Section 70.10 – Federal Oversight and Sanctions

Section 70.11 – Requirements for Enforcement Authority

Part 72 – Regulations on Permits

Subpart A – Acid Rain program General Provisions

Section 72.1 Purpose and Scope

Section 72.2 – Definitions

Section 72.3 – Measurements, Abbreviations, and Acronyms

Section 72.4 – Federal Authority

Section 72.5 – State Authority

Section 72.6 – Applicability

Section 72.9 – Standard Requirements

Section 72.10 – Availability of Information

Section 72.11 – Computation of Time

Section 72.12 – Administrative Appeals

Section 72.13 – Incorporation by Reference

Subpart B – Designated Representative

Section 72.20 – Authorization and Responsibilities of the Designated

Section 72.21 – Submissions

Section 73.35 – Compliance

Section 73.36 – Banking

Section 73.37 – Account Error and Dispute Resolution

Section 73.38 – Closing of Accounts

Subpart D – Allowance Transfers

Section 73.50 – Scope and Submission of Transfers

Section 73.51 – Prohibition

Section 73.52 – EPA Recordation

Section 73.53 – Notification

Subpart E – Auctions, Direct Sales, and Independent Power Producers Written

Section 73.70 – Auctions

Section 73.71 – Bidding

Section 73.72 – Direct Sales

Section 73.73 – Selegation of Auctions and Sales and Termination of Auctions

Section 73.74 – Independent Power Producers Written Guarantee

Section 73.75 – Application for an IPP Written Guarantee

Section 73.76 – Approval and Exercise of the IPP Written Guarantee

Section 73.77 – Relationship of Independent Power Producers Written Guarantee

Section 75.5 – Prohibitions

Section 75.6 – Incorporation by Reference

Section 76.7 – EPA Study

Section 76.8 – [Reserved]

Subpart – Monitoring Provisions

Section 75.10 – General Operating Requirements

Section 75.11 – Specific Provisions for Monitoring SO2 Emissions

Section 75.12 – Specific Provisions for Monitoring NOx Emissions (NOx and Flow)

Section 75.13 – Specific Provisions for Monitoring CO2 Emissions

Section 75.14 – Specific Provisions for Monitoring Capacity

Section 75.15 – Specific Provisions for Monitoring SO2 Emissions Removal By

Section 75.16 – Specific Provisions for Monitoring Emissions from Common, By

Section 76.6 – NOx Emission Limitations for Group 2 Boilers [Reserved]

Section 76.7 – Revised NOx Emission Limitations for Group 1, Phase II Boilers

Section 76.8 – Early Election for Group 1, Phase II Boilers

Section 76.9 – Permit Application and Compliance Plans

Section 76.10 – Alternative Emission Limitations

Section 76.11 – Emissions Averaging

Section 76.12 – Phase I NOx Compliance Extensions

Section 76.13 – Compliance and Excess Emissions

Section 76.14 – Monitoring, Recordkeeping, and Reporting

Section 76.15 – Test Methods and Procedures

Section 76.16 – [Reserved]

Part 77 – Excess Emissions

State Applicable Requirements

Chapter 62-4, F.A.C.; PERMITS

62-4.055 – Permit Processing

Chapter 62-210, F.A.C.; STATIONARY SOURCES – GENERAL REQUIREMENTS

62-210.550 – Stack Height Policy

62-210.700 Excess Emissions

Chapter 62-212, F.A.C.; STATIONARY SOURCES – PRECONSTRUCTION REVIEW

62-212.300 – General Preconstruction Review Requirements

62-212.400 – Prevention of Significant Deterioration

62-212.410 – Best Available Control Technology

Chapter 62-213, F.A.C.; OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION

62-213.413 – Fast-Track Revisions of Acid Rain Parts

Chapter 62-214, F.A.C.; REQUIREMENTS FOR SOURCES SUBJECT TO THE FEDERAL ACID RAIN PR

62-214.300 – Applicability

62-214.320 – Applications

62-214.330 – Acid Rain Compliance Plan and Compliance Options

62-214.350 – Certification

62-214.370 – Revisions Administration Corrections

62-214.420 – Acid Rain Part Content

62-214.430 – Implementation and Termination of Compliance Options

Chapter 62-272, F.A.C.; AMBIENT AIR QUALITY STANDARDS

62-272.500 – Maximum Allowable Increases

Chapter 62-273, F.A.C.; AIR POLLUTION EPISODES

62-273.300 – Air Pollution Episodes

62-273.400 – Air Alert

62-273.500 – Air Warning

62-273.600 – Air Emergency

Chapter 62-296, F.A.C.; STATIONARY SOURCES – EMISSION STANDARDS

62-296.405 – Fossil Fuel Steam Generators

Chapter 62-297, F.A.C.; STATIONARY SOURCES – EMISSIONS MONITORING

62-297.401 – Compliance Test Methods

62-297.440 – Supplementary Test Procedures

62-297.520 – EPA Performance Specifications

62-297.620 – Exceptions and Approval of Alternate Procedures and Requirements

62-297.310 – General Test Requirements

Subpart F – Energy Conservation and Renewable Energy Reserve

Section 73.80 – Operation of Allowance Reserve Program for Conservation..

Section 73.81 – Quantified Conservation Measures and Renewable Energy

Section 73.82 – Application for Allowances from Reserve Program

Section 73.83 – Secretary of Energy's Action on New Income Neutality

Section 73.84 – Administrator's Action on Applications

Section 73.85 – Administrator Review of the Reserve Program

Section 73.86 – State Regulatory Autonomy, Appendix A to Subpart F....List of

Part 75 – Emission Monitoring

Subpart A – General

Section 75.1 – Purpose and Scope

Section 75.2 – Applicability

Section 75.3 – General Acid Rain Program Provisions

Section 75.4 – Compliance Dates

Subpart C – Operation and Maintenance Requirements

Section 75.20 – Certification and Recertification Procedures

Section 75.21 – Quality Assurance and Quality Control Requirements

Section 75.22 – Reference Test Methods

Section 75.23 – Alternatives to ASTM Methods

Section 75.24 – Out-of-Control Periods

Subpart D – Missing Data Substitution Procedures

Section 75.30 – General Procedures

Section 75.31 – Initial Missing Data Procedures

Section 75.32 – Determinations of Monitor Data Availability for Standard Missing Data

Section 75.33 – Standard Missing Data Procedures

Section 75.34 – Units with Add-on Emission Controls

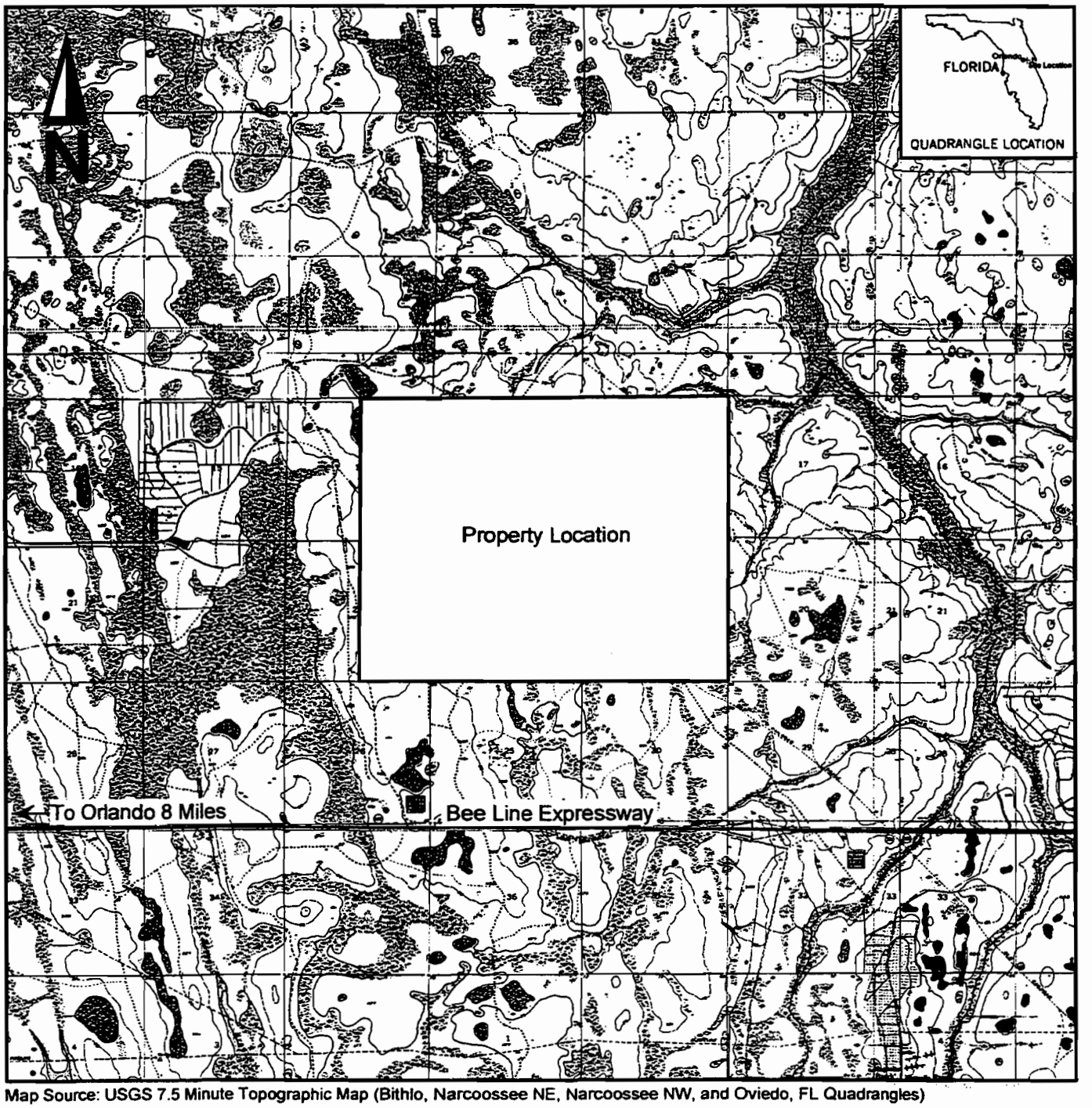
Subpart E – Alternative Monitoring Systems

Subpart 75.40 – General Demonstration Requirements

1,680,000 Gallon Fuel Oil Storage Tank
Unit Specific Applicable Requirements

Applicable Regulations	Applicable Requirement
40 CFR 60, Subpart Kb	Stanbdards of Performance for Volatile Organic Liquid Storage Vellessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 19984.
40 CFR 60.116b, Monitoring of OpOperations	The owneror or poperator shall keep records according to the provisions of 40 cCFR 60.116b (a) and (b) for a period of at least two (2) years.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission f air pollutants without the applicalbe air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of Excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.

Attachment B
Area Map Showing Facility Location



Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)

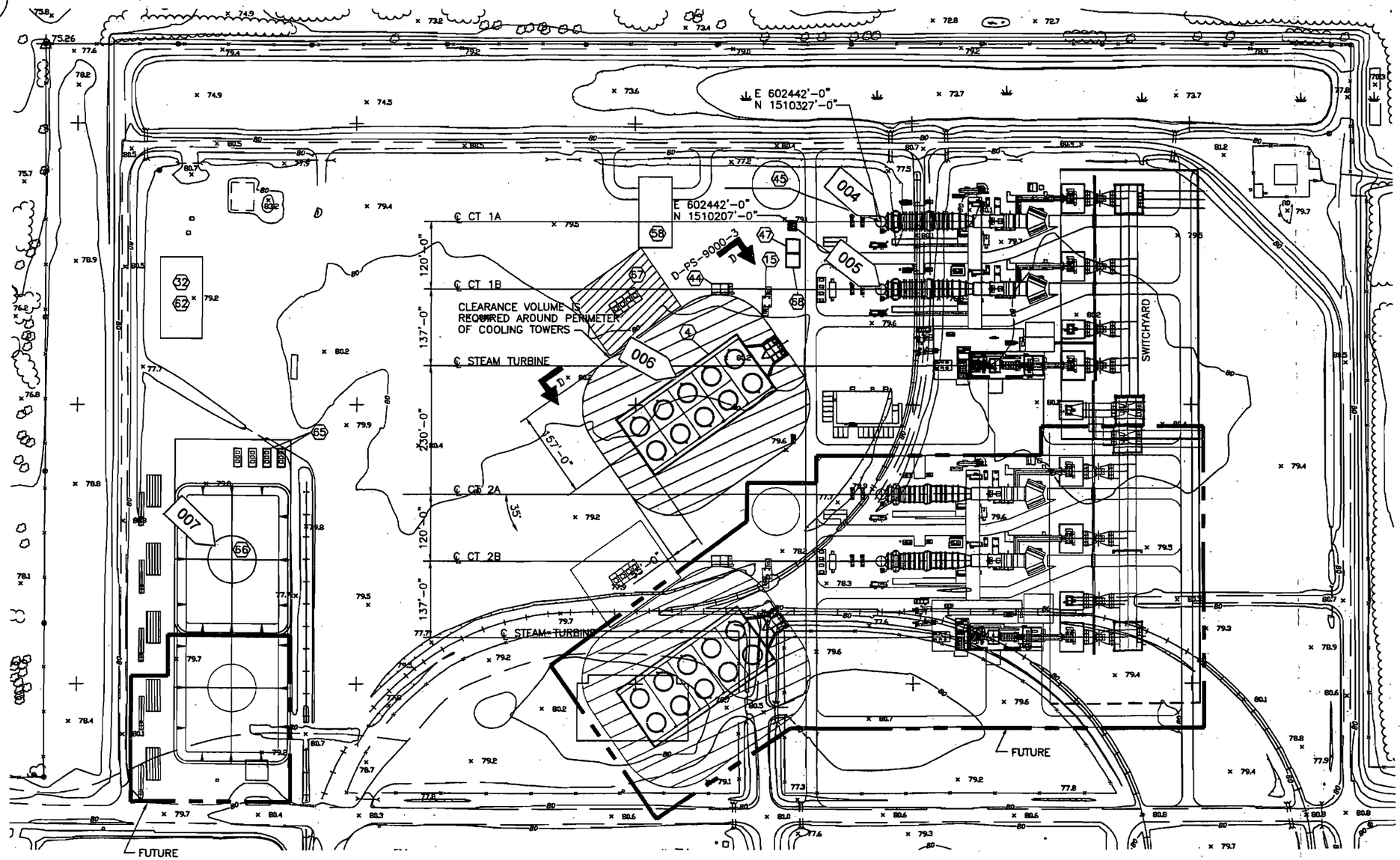
Miles

0 1 2 3

Stanton Energy Center
Property Location

Attachment C
Facility Plot Plan

D-PS-9000-1



NOTES:

NEW STACK COORDINATES BASED ON NAD83 FLORIDA STATE PLANES, EASTERN ZONE, U.S. FOOT:

CENTER UNIT 1A HRSG STACK:	E 602442'-0"	N 1510327'-0"
CENTER UNIT 1B HRSG STACK:	E 602442'-0"	N 1510207'-0"
CENTER UNIT 2A HRSG STACK:	E 602442'-0"	N 1509840'-0"
CENTER UNIT 2B HRSG STACK:	E 602442'-0"	N 1509720'-0"

NEW STACK COORDINATES BASED ON NAD83 UTM, ZONE 16 NORTH, METER:

CENTER UNIT 1A HRSG STACK:	E 1071425.2056	N 3165216.3816
CENTER UNIT 1B HRSG STACK:	E 1071427.0434	N 3165179.7166
CENTER UNIT 2A HRSG STACK:	E 1071432.6637	N 3165067.5830
CENTER UNIT 2B HRSG STACK:	E 1071434.5014	N 3165030.9181

⬡ DENOTES EQUIP. NO. – SEE D-PS-9000-2 FOR DESCRIPTION

REFERENCES:

D-PS-9000-2	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=60'-0"
D-PS-9000-3	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS
D-PS-9000-4	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=400'-0"

CAD 9000-1D.DWG
AutoCad | SHW-14

PRELIMINARY

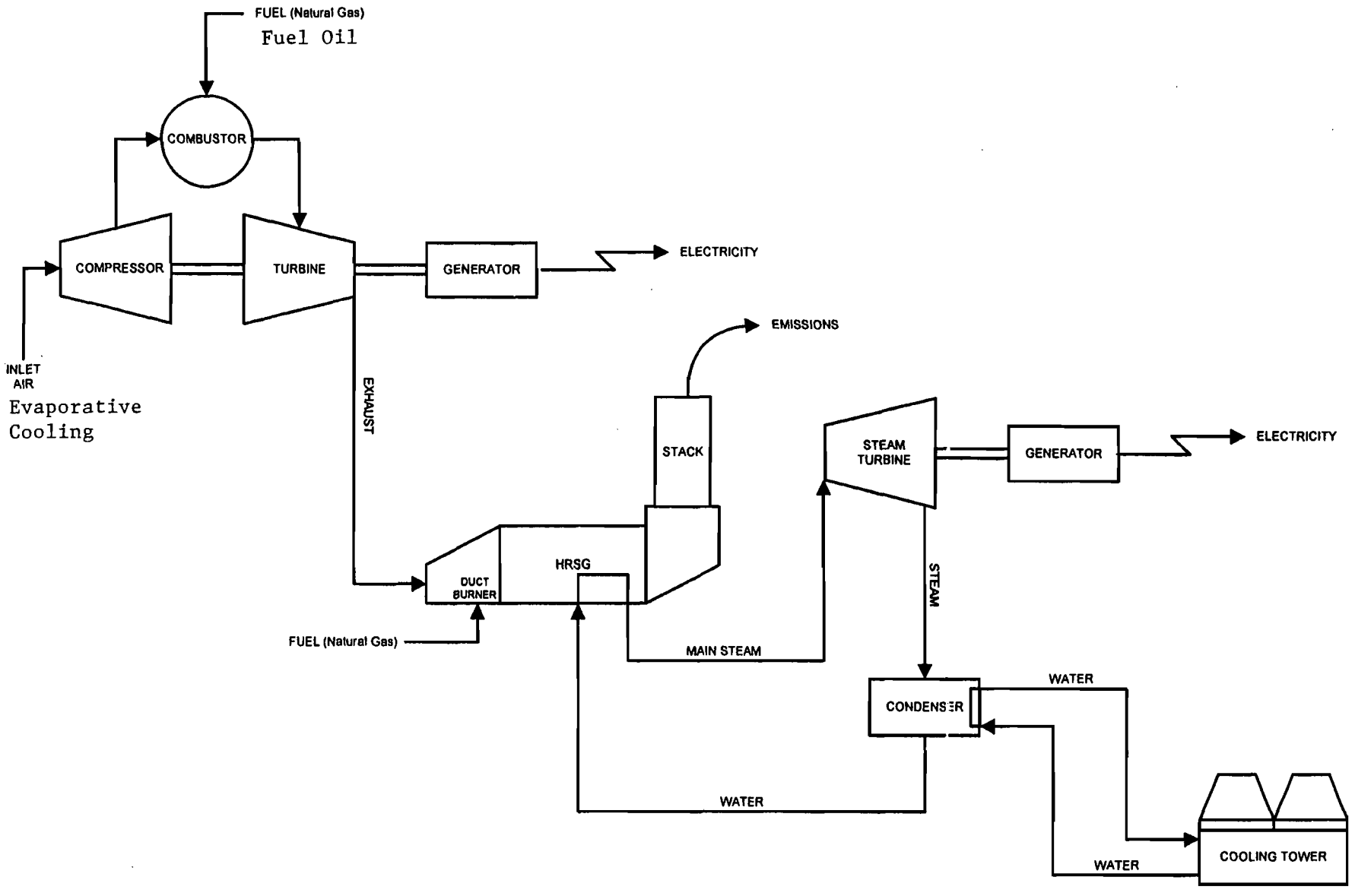
Southern Company Services, Inc.
FOR
SOUTHERN–FLORIDA, LLC

STANTON ENERGY CENTER – UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=200'-0"

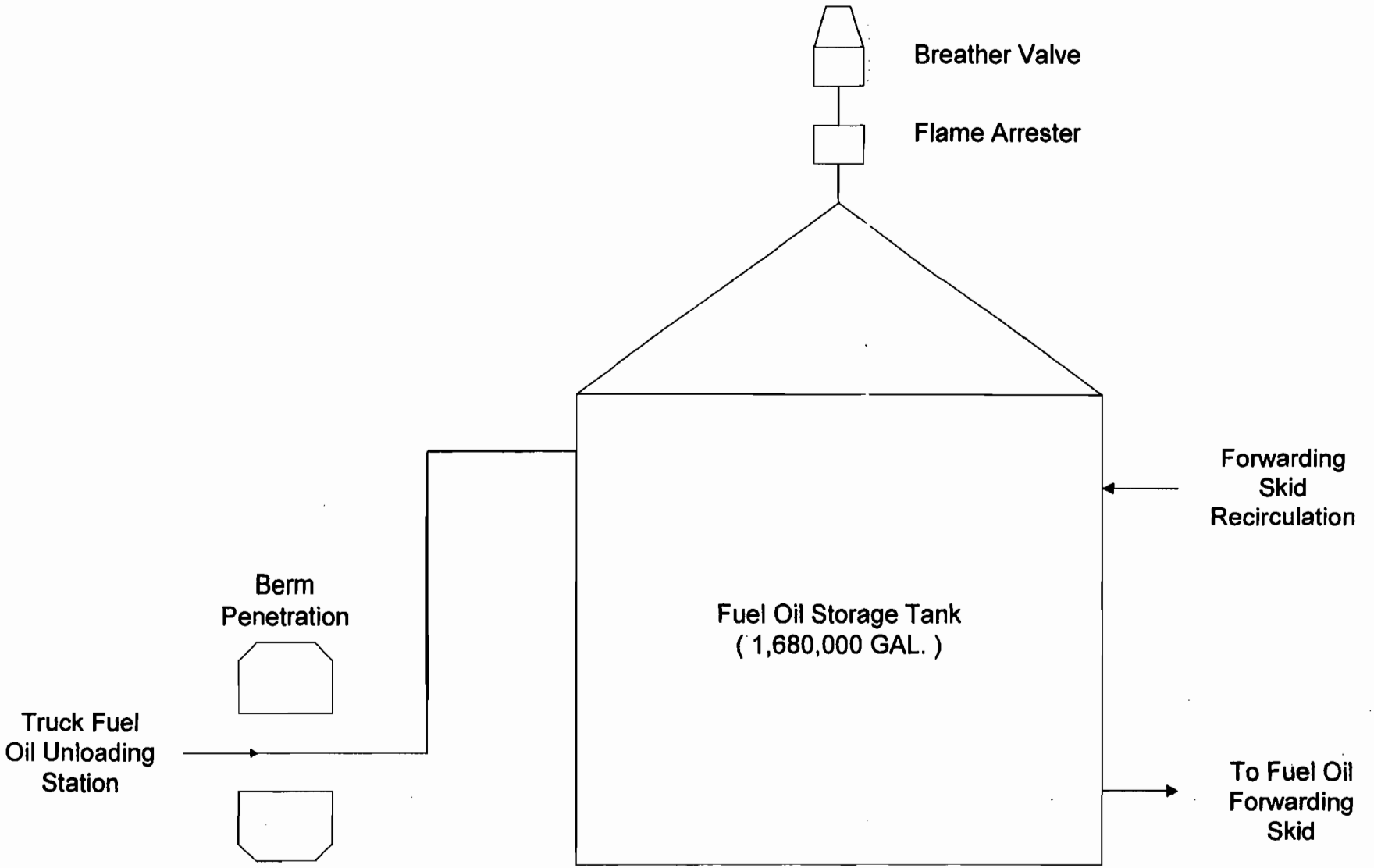
REVISION	DATE	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
1. REVISED TITLE BLOCK	01/16/00	SHW						
1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO. 68	12/7/00	DWR						
1. ADDED SERVICE WATER COOLER 1. ADDED LOCATION OF FUTURE BLOCK.	10/24/00	SHW						
ISSUED FOR REVIEW	9/22/00	SHW						

DESIGNED SHW DRAWN SHW CHECKED
SCALE 1"=200'-0" | PROJECT I.D. | DRAWING NUMBER D-PS-9000-1 | REV. D

Attachment D
Process Flow Diagram



Combined Cycle Combustion Turbine
Process Flow Diagram


Breather Valve
Flame Arrester
Forwarding
Skid
Recirculation
Berm
Penetration
Fuel Oil Storage Tank
(1,680,000 GAL.)
Truck Fuel
Oil Unloading
Station
To Fuel Oil
Forwarding
Skid

Attachment E
Fuel Analysis

The primary fuel for the Project is natural gas and the backup fuel is low sulfur (0.05 percent) No. 2 fuel oil. Operation on oil is proposed to be limited to 1,000 hours per year, per unit. Tables E-1 and E-2 present typical property values for the primary and backup fuels, respectively.

Table E-1
Natural Gas Properties

Parameter	Mole, percent	Gal/Mcf**	Btu*	Rel Den*
C6+	0.075	0.029	60.0	0.00015
Propane	0.665	0.182	342.0	0.00077
I-Butane	0.152	0.049	101.0	0.00023
N-Butane	0.130	0.041	87.0	0.00020
I-Pentane	0.040	0.015	33.0	0.00008
N-Pentane	0.020	0.007	16.0	0.00004
Nitrogen	0.309	0.000	0.0	0.00023
Methane	95.067	0.000	1,9209.0	0.04006
CO_2	0.881	0.000	0.0	0.00102
Ethane	2.661	0.708	957.0	0.00210
Totals	100.0	1.031	2,0798.0	0.04488

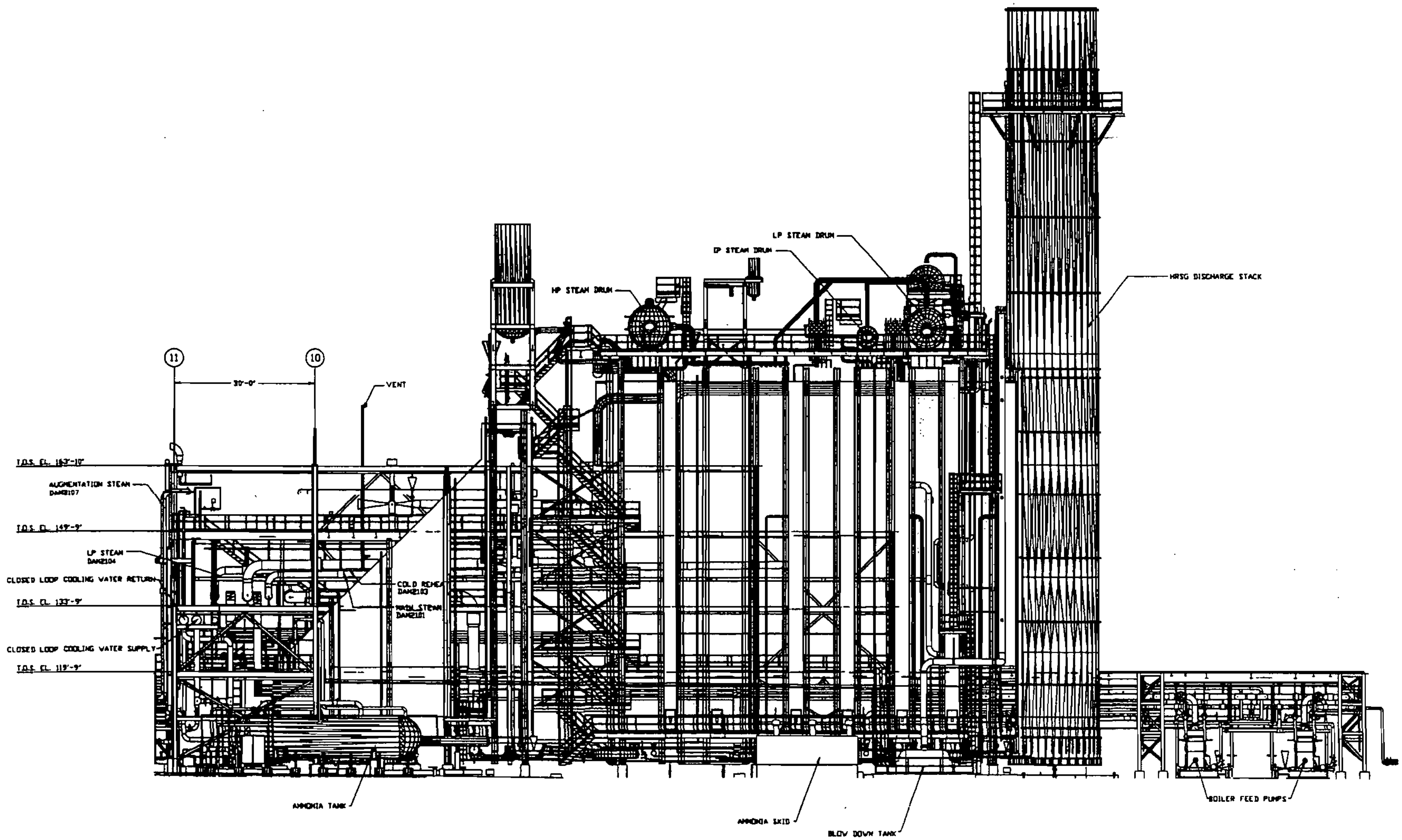
*The component C6+ is assumed to be C6H6 only.

**The density for each component is evaluated under a pressure of 14.64 psia.

Table E-2 Typical No. 2 Fuel Oil Properties	
Parameter	Value
Ash Content, percent wt	0.001
Sulfur Content by XRF, percent wt	<0.05
Water Content KF, percent wt	<0.50 percent
Density, kg/l at 15 C	0.8422
Gross Heat Value, Btu/gal	138,000
Net Heat Value, Btu/gal	129,575
Gross Heat Value, Btu/lb	19,756
Net Heat Value, Btu/lb	18,550
Arsenic, ppm	<0.05
Beryllium, ppm	<0.05
Mercury, ppm	<0.05
Lead, ppm	0.07

Attachment F
Stack Sampling Facilities

The stack sampling facilities will be installed in accordance with Rule 62-297 310 (6).

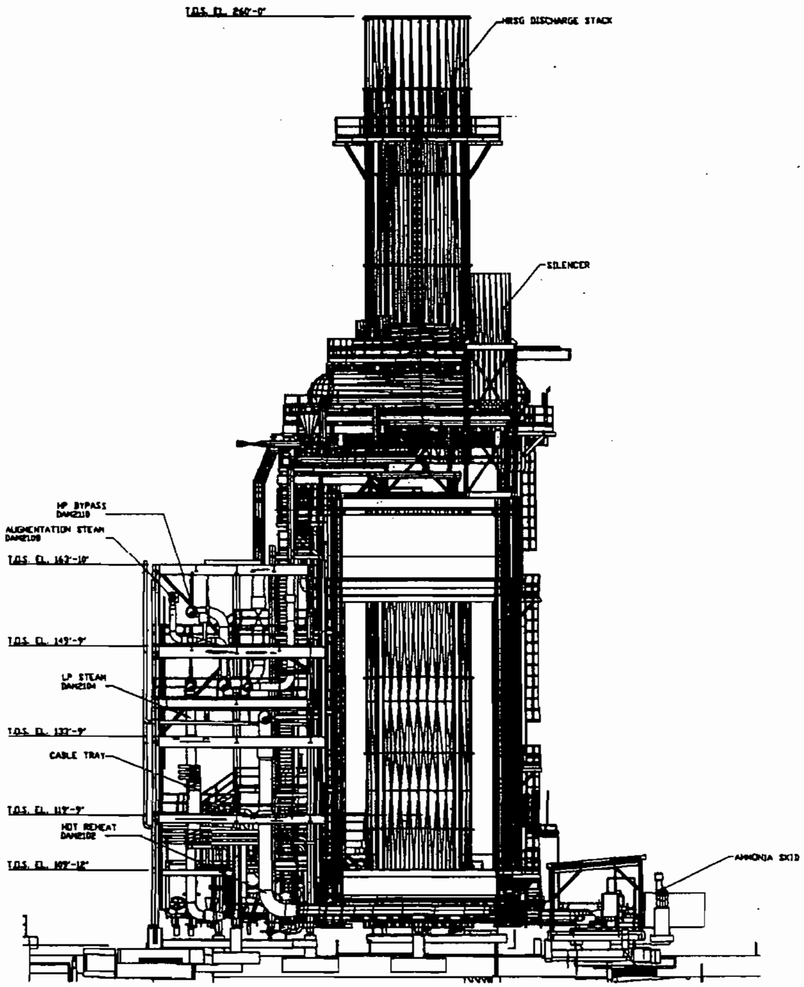


SECTION "H-H"

SEE DWG. DAM2501 SH. 1

REVISION A	DATE 4/15/02	Southern Company Services, Inc. FOR
FOR INFORMATION ONLY		Southern Company - Florida
		Stanton Energy Center Combined Cycle Unit A GENERAL ARRANGEMENT SECTION "H-H"
RLH | GAH | VBF | TFK | SEV | JRK | RV1	1/8"=1'-0"	DAM2501 | 9 | 10 | A

08:47:23 AM 3/25/2003 RMMAR



SECTION "J-J"

SEE DWG. DAM2501 SH. 1

REVISION A	DATE 4/15/02
FOR INFORMATION ONLY	

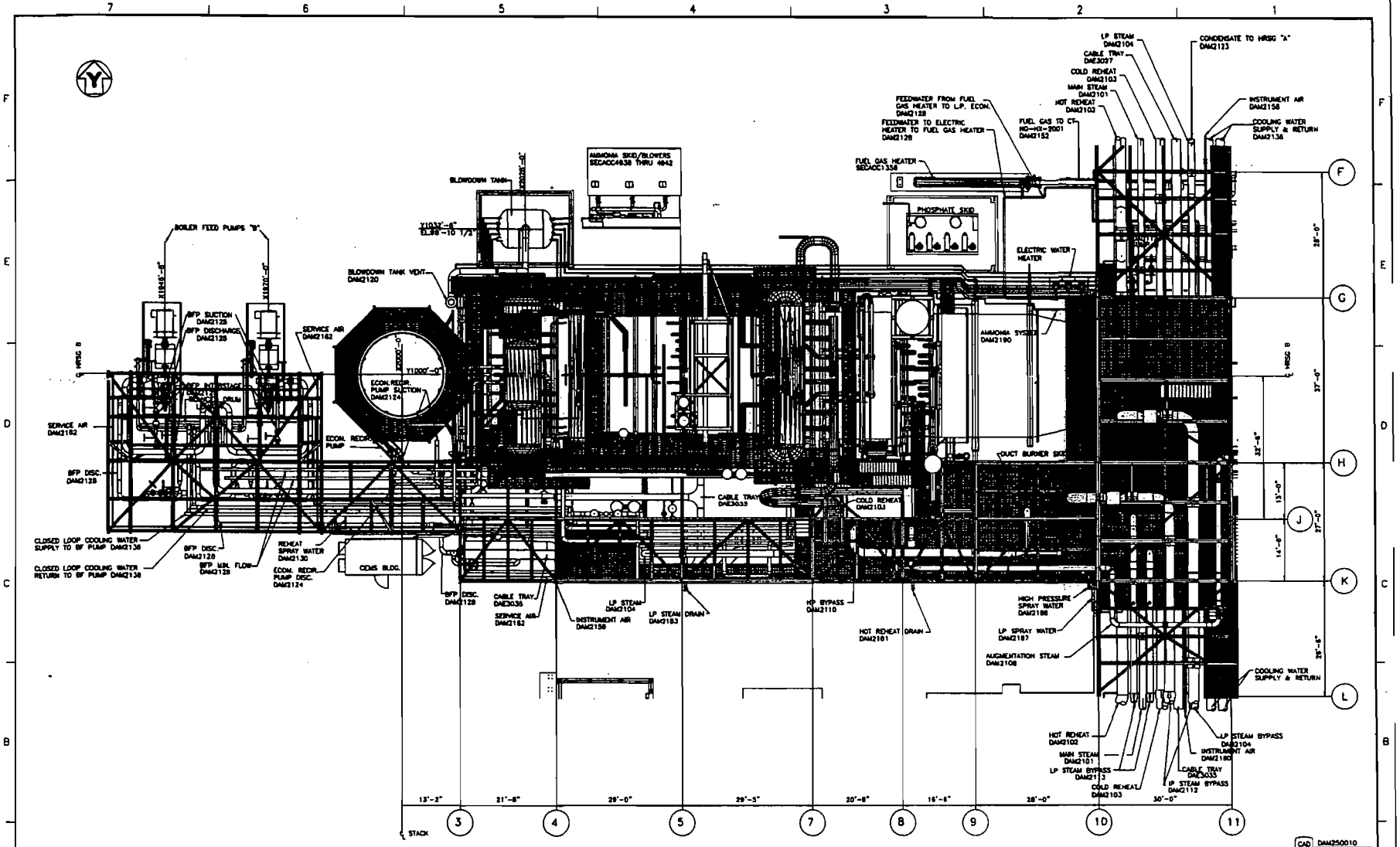
Southern Company Services, Inc.

Southern Company - Florida

Stanton Energy Center Combined Cycle Unit A
GENERAL ARRANGEMENT
SECTION "J-J"

RLH	GAH	VBF	TFH	SEV	JRK	RVI	3/16"=1'-0"	DAM2501	10	11	A

08:34:50 AM 3/25/2003 RMM



PLAN HRSG-B

CAD DAM2500010 | 2000i | JFR -02

REVISION	DATE
REVISION A	DATE 01-09-02

FOR INFORMATION ONLY
JOB NO. 3130MW

Southern Company Services, Inc.
FOR
Southern Company-Florida

Stanton Energy Center CC Unit A
GENERAL ARRANGEMENT SITE PLAN
HRSG-B

JFR	RGC	BWF	TFM	SEW	JRK	RWI

1/8"=1'-0" | 3130MW | DAM2500 | 10 | 11 | A

08:40:25 AM 3/25/2003 RMMA

Attachment G
Operating Matrix

ALTERNATIVE METHODS OF OPERATION
Stanton Units 25 & 26

1. **Combustion Turbine Unit operated under normal conditions between 50 – 100 % load utilizing natural gas as the primary fuel with no duct burners in service.**

2. **Combustion Turbine Unit operated under normal conditions between 50 – 100% load utilizing No. 2 fuel oil as the primary fuel with no duct burners in service.**

3. **Combustion Turbine Unit operated under normal conditions between 50 – 100 % load utilizing natural gas as the primary fuel with no duct burners in service with evaporative cooling.**

4. **Combustion Turbine Unit operated under normal conditions between 50 – 100% load utilizing No. 2 fuel oil as the primary fuel with no duct burners in service with evaporative cooling.**

5. **Combustion Turbine Unit operated under normal conditions between 50 – 100% load utilizing natural gas as the primary fuel with all duct burners in service using natural gas.**

6. **Combustion Turbine Unit operated under normal conditions between 50 – 100% load utilizing No. 2 fuel oil as the primary fuel with all duct burners in service using natural gas.**

7. **Combustion Turbine Unit operated under normal conditions between 50 – 100% load utilizing natural gas as the primary fuel with all duct burners in service using natural gas and evaporative cooling.**

8. **Combustion Turbine Unit operated under normal conditions between 50 -100% load utilizing No. 2 fuel oil as the primary fuel with all duct burners in service using natural gas and evaporative cooling.**

9. **Combustion Turbine Unit operated under normal conditions between 50 -100% load utilizing natural gas as the primary fuel with all duct burners in service using natural gas and evaporative cooling plus power augmentation.**

10. **Combustion Turbine Unit operated under normal conditions between 50 -100% load utilizing No. Fuel oil as the primary fuel with all duct burners in service using natural gas and evaporative cooling plus power augmentation.**

Note: Startup and Shutdown operations are defined as any operation less than 50% load using natural gas or No. 2 fuel oil. Special alternative emission limitations are outlined in the PSD permit for these operations.

Table 1
Combustion Turbine Operating Scenarios

Case	Ambient Temperature (°F)	Load (%)	CTG-1	CTG-2	Evaporative Cooling	Power Augmentation	Duct Burner
Natural Gas							
1	19	100	X	X			
2	19	75	X	X			
3	19	50	X	X			
4	19	100	X	X			X
5	45	100	X	X			
6	45	75	X	X			
7	45	50	X	X			
8	45	100	X	X			X
9	60	100	X	X	X	X	X
10	70	100	X	X	X		
11	70	75	X	X			
12	70	50	X	X			
13	70	100	X	X	X		X
14	95	100	X	X	X		
15	95	75	X	X			
16	95	50	X	X			
17	95	100	X	X	X	X	X
18	95	100	X	X	X	X	X
19	95	100	X	X	X		X
Distillate Fuel Oil							
20	19	100	X	X			
21	19	75	X	X			
22	19	50	X	X			
23	45	100	X	X			
24	70	100	X	X	X		
25	95	100	X	X	X		

Attachment H
Acid Rain Permit Application

One Energy Place
Pensacola, Florida 32520

Tel 850.444.6111

GULF POWER
A SOUTHERN COMPANY

April 15, 2002

Certified Mail

Mr. Scott M. Sheplak, P.E.
Department of Environmental Protection
2600 Blair Stone Road
Mail Station #5510
Tallahassee, Florida 32399-2400

Dear Mr. Sheplak:

RE: Stanton A Combined Cycle Acid Rain Permit Application
Stanton A (ORIS Code: 55821)
Permit No: 0950137-002-AC, PSD-FL-313

Attached, please find one original and one copy of the Phase II Acid Rain Permit Application for the Stanton A electric generating plant (ORIS Code 55821). The application includes a request to add two new generating units (i.e. Units 25 and 26) at the site. These units are the new combined cycle units under current PSD review by the Department. (See PSD-FL-313). A corresponding notice for Certification of Representation for Stanton A is being submitted to EPA. Please note that Stanton A has a different ORIS Code from the existing Stanton Energy Center operated by OUC.

If you have any questions or need further information regarding the addition of these units under the Acid Rain Program at Stanton A, please call me at (850) 444.6527.

Sincerely,

G. Dwain Waters, Q.E.P.
Air Quality Programs Supervisor

cc: Robert G. Moore, Gulf Power Company
James O Vick, Gulf Power Company
Denise Stalls, Stanton Energy Center, OUC
Stacey Miles, Southern Company
Danny Herrin, Southern Company Services
Douglas Neeley, EPA – Region IV

Phase II Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: ☒ New ☐ Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name	Stanton A	State	FL	ORIS Code	55821

STEP 2 Enter the unit ID# for each affected unit and indicate whether a unit is being repowered and the repowering plan being renewed by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e.

a	b	c	d	e
Unit ID#	Compliance Plan: Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Compliance Plan: Repowering Plan	New Units: Commence Operation Date	New Units: Monitor Certification Deadline
25	Yes	No	4/01/2003	7/01/2003
26	Yes	No	4/01/2001 ~~3~~	7/01/2003
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "Yes" for any unit

☐ For each unit that is being repowered, the Repowering Extension Plan form is included.

Stanton A
Plant Name (from Step 1)

STEP 4
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

Acid Rain Part Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the Department determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain part;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the Department; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain part application, the Acid Rain part, or an exemption under 40 CFR 72.7, 72.8, or 72.14 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the Department:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Stanton A
Plant Name (from Step 1)

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7, 72.8 or 72.14, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7, 72.8, or 72.14 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **James O. Vick**	
Signature James O. Vick	Date 4/15/02

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

April 24, 2002

Mr. G. Dwain Waters, Q.E.P.
Air Quality Programs Supervisor
Gulf Power Company
One Energy Place
Pensacola, FL 32520

Re: Acid Rain Phase II Permit Application
Stanton A Electric Generating Plant; ORIS Code: 55821

Dear Mr. Waters:

Thank you for your recent submission of the Acid Rain Phase II Permit Application and Certificate of Representation for the subject facility. We have reviewed the documents and deem your application to be complete.

Sincerely,

Scott M. Sheplak, P.E.
Administrator
Title V Section

cc: Jenny Jachim, EPA Region 4

Allowance Tracking System Report

Date: 5/22/02

ACCOUNT INFORMATION

Account Number	055821000025
Plant/Account Name	Stanton A
AAR ID Number	2445
AAR Name	W. Paul Bowers
AAR Address	600 North 18th Street
AAR Address	15th Floor
AAR City	Birmingham
AAR State	AL
AAR Zip	35203
AAR Phone	205 - 257 - 5355
AAR Fax	205 - 257 - 0526
AAR Email	wpbowers@southernco.com
ALT ID Number	706
ALT Name	James O. Vick
ALT Phone	850 - 444 - 6311
ALT Fax	850 - 444 - 6217
ALT Email	jovick@southernco.com

Binding Party Information

Binding Party Name	Binding Party Type
Kissimmee Utility	Owner
Orlando Utilities Commision	Owner
Florida Municipal Power Authority	Owner
Southern Company - Florida, LLC	Owner/Operator

AAR History:

AAR NAME	AAR/ ALTERNATE	START	END
James O. Vick	ALT	05/21/2002	CURRENT
W. Paul Bowers	AAR	05/21/2002	CURRENT

Please review the information shown above and report any errors, along with supporting documentation, to the address listed below, or call the Acid Rain Hotline.

ACID RAIN PROGRAM

U.S. Environmental Protection Agency
Clean Air Markets Division (6204-N)
U.S. mail address: 1200 Pennsylvania Ave., NW
Washington, DC 20460
Overnight mail address: 633 3rd Street, NW
Washington, DC 20001

Acid Rain Hotline: (202)564-9620

Allowance Tracking System Report

ACCOUNT INFORMATION

Account Number	055821000026
Plant/Account Name	Stanton A
AAR ID Number	2445
AAR Name	W. Paul Bowers
AAR Address	600 North 18th Street
AAR Address	15th Floor
AAR City	Birmingham
AAR State	AL
AAR Zip	35203
AAR Phone	205 - 257 - 5355
AAR Fax	205 - 257 - 0526
AAR Email	wpbowers@southernco.com
ALT ID Number	706
ALT Name	James O. Vick
ALT Phone	850 - 444 - 6311
ALT Fax	850 - 444 - 6217
ALT Email	jovick@southernco.com

Binding Party Information

Binding Party Name	Binding Party Type
Kissimmee Utility	Owner
Orlando Utilities Commision	Owner
Florida Municipal Power Authority	Owner
Southern Company - Florida, LLC	Owner/Operator

AAR History:

AAR NAME	AAR/ ALTERNATE	START	END
James O. Vick	ALT	05/21/2002	CURRENT
W. Paul Bowers	AAR	05/21/2002	CURRENT

Please review the information shown above and report any errors, along with supporting documentation, to the address listed below, or call the Acid Rain Hotline.

ACID RAIN PROGRAM

U.S. Environmental Protection Agency
Clean Air Markets Division (6204-N)
U.S. mail address: 1200 Pennsylvania Ave., NW
Washington, DC 20460
Overnight mail address: 633 3rd Street, NW
Washington, DC 20001

Acid Rain Hotline: (202)564-9620

Attachment I
TANKS Calculation

TANKS 4.0
Emissions Report - Detail Format
Tank Identification and Physical Characteristics

Identification

User Identification:	007
City:	Pensacola
State:	Florida
Company:	OUC
Type of Tank:	Vertical Fixed Roof Tank
Description:	Fuel Oil Storage Tank

Tank Dimensions

Shell Height (ft):	40.00
Diameter (ft):	82.23
Liquid Height (ft):	38.50
Avg. Liquid Height (ft):	19.25
Volume (gallons):	1,680,000.00
Turnovers:	17.14
Net Throughput (gal/yr):	28,800,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft):	0.00
Radius (ft) (Dome Roof):	43.12

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Orlando, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	74.32	68.84	79.80	72.34	0.0103	0.0086	0.0122	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)

Annual Emission Calculations	
Standing Losses (lb):	633.8478
Vapor Space Volume (cu ft):	204,547.5111
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.0372
Vented Vapor Saturation Factor:	0.9795
Tank Vapor Spece Volume	
Vapor Space Volume (cu ft):	204,547.5111
Tank Diameter (ft):	82.2300
Vapor Space Outage (ft):	38.5162
Tank Shell Height (ft):	40.0000
Average Liquid Height (ft):	19.2500
Roof Outage (ft):	17.7662
Roof Outage (Dome Roof)	
Roof Outage (ft):	17.7662
Dome Radius (ft):	43.1150
Shell Radius (ft):	41.1150
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Daily Avg. Liquid Surface Temp. (deg. R):	533.9945
Daily Average Ambient Temp. (deg. F):	72.3167
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.0067
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Peint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft dey):	1,486.6667
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0372
Daily Vapor Temperature Range (deg. R):	21.9205
Daily Vapor Pressure Range (psia):	0.0035
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0086
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0122
Daily Avg. Liquid Surface Temp. (deg R):	533.9945
Daily Min. Liquid Surface Temp. (deg R):	528.5143
Daily Max. Liquid Surface Temp. (deg R):	539.4746
Daily Ambient Temp. Range (deg. R):	20.6167
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9795
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Vapor Space Outage (ft):	38.5162
Working Losses (lb):	915.1126

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)- (Continued)

Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0103
Annual Net Throughput (gal/yr.):	28,800,000.0000
Annual Turnovers:	17.1400
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	1,680,000.0000
Maximum Liquid Height (ft):	38.5000
Tank Diameter (ft):	82.2300
Working Loss Product Factor:	1.0000

Total Losses (lb):	1,548.9604

TANKS 4.0
Emissions Report - Detail Format
Individual Tank Emission Totals

Annual Emissions Report

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	915.11	633.85	1,548.96

Attachment J
Unregulated and Insignificant Activities List

Insignificant Activities List
Stanton A Combined Cycle Units

Sulfuric Acid Tank – 5,750 gallon tank for ph control in cooling tower
Battery bank – 5,808 pounds containing sulfuric acid
Anhydrous Ammonia Tank - 18,000 gallon pressurized tanking system
Aqueous Ammonia – 350 gallon totes (500 gallons on site at all times)
Chlorine cylinders – 6 each at 12,000 pounds
Used Oil drums – (55 gallon drums)
Generic type insignificant activities include the following:

1. Internal combustion engines - mobile sources
2. Vacuum pumps for labs
3. Steam cleaning equipment
4. Lab equipment used for chemical or physical analyses
5. Brazing, soldering or welding equipment
6. One or more emergency generators located within a single facility provided:
   a. None of the emergency generators is subject to the Federal Acid Rain Program; and
   b. Total fuel consumption by all such emergency generators within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
7. One or more heating units and general purpose internal combustion engines, or other combustion devices, all of which are located within a single facility are not listed elsewhere in Rule 62-210.300(3)(a), F.A.C., and are not pollution control devices, provided:
   a. None of the heating units, general purpose internal combustion engines, or other combustion devices that would be exempted is subject to the Federal Acid Rain Program; and
   b. Total fuel consumption by all such heating units, general purpose internal combustion engines, and other combustion devices that would be exempted is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
8. Fire and safety equipment
9. Surface coating operation within a single facility if the total quantity of coatings containing greater than 5.0 percent VOCs, by volume, used is 6.0 gallons per day or less, averaged monthly, provided:
   a. Such operations are not subject to a volatile organic compound Reasonably

Available Control Technology (RACT) requirement of Chapter 62-296, F.A.C.; and

b. The amount of coatings used shall include any solvents and thinners used in the process including those used for cleanup.

10. Surface coating operations utilizing only coatings containing 5.0 percent or less VOCs, by volume.
11. Space heating equipment (non-boilers)
12. Sand blasting and abrasive grit blasting
13. Vehicle refueling operations
14. Storage tanks less than 550 gallons
15. Architectural (equipment) maintenance painting
16. Diesel fuel oil truck unloading
17. Petroleum lubrication systems
18. Any other emissions unit or activity that:

a. Is not subject to a unit-specific applicable requirement.

b.In combination with other units and activities proposed as insignificant, would not cause the Stanton Energy Center to exceed any major source threshold(s) as defined by Rule 62-213.420(3)(c)1., F.A.C. unless acknowledged in a permit application.

c. Would neither emit nor have the potential to emit:

i. 500 pounds per year of lead and lead compounds expressed as lead;
ii. 1,000 pounds per year or more of any hazardous air pollutant;
iii. 2,500 pounds per year or more of total hazardous air pollutants; or
iv. 5.0 tons per year or more of any other regulated pollutant.

Attachment K
Title V Permit Change Request

One Energy Place
Pensacola, Florida 32520

Tel 850.444.6111

GULF POWER
A SOUTHERN COMPANY

Certified Mail

October 30, 2003

Mr. Scott M. Sheplak
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Mail Station #5510
Tallahassee, Florida 32399-2400

Dear Mr.Sheplak:

RE: Curtis H. Stanton Energy Center – Title V Unit Addition
DEP File No: 0950137-002-AC
DEP File No. PA 81-14SA2, PSD-FL-313

Earlier this year, Southern Company – Florida, LLC completed construction of the new combined cycle Units 25 & 26 at the Curtis H. Stanton Energy Center as outlined in the PSD Permit FL-313. All conditions, CEMS certifications and compliance testing were completed with satisfactory results and all reports have been submitted to the Department. The next stage of permitting is the addition of these units to the Stanton Title V Permit.

Please find attached one original and three copies of the completed Title V Permit application for Stanton A Combined Cycle Units 25, 26, 27 & 28 as previously designated in the PSD permit.

Please let me know if you have any questions regarding our application.

Sincerely,

G. Dwain Waters, Q.E.P.
Air Quality Programs Supervisor

cc:w attachment:
James O. Vick, Gulf Power Company
Robert Schaffeld, Southern Company
Ronald H. Walston, Southern Company
Denise Stalls, Orlando Utilities Commission
Thomas W. Davis, Environmental Consulting & Technology, Inc.

cc:w/o attachment:

Danny Herrin, Southern Company Services
Lance Harman, Southern Company
Heather Turner, Southern Company
Garry Kurberski, Central District – FDEP
Ben Sharma, Kissimmee Utility Authority
Rick Casey, Florida Municipal Power Agency

Attachment L
Precautions to Prevent Emissions of Unconfined Particulate Matter

"Unconfined particulate matter (PM) emissions that may result from operations at the Stanton A Combined Cycle Unit include:

- Vehicular traffic on paved and unpaved roads;
- Wind-blown dust from yard areas; and.
- Periodic abrasive blasting

The following techniques may be used to control unconfined PM emissions on an as-needed basis:

- Paving and maintenance of roads, parking areas, and yards.
- Chemical (dust suppressants) or water application to:
  - Unpaved roads.
  - Unpaved yard areas.
- Removal of PM from roads and other paved areas to prevent reentrainment and from buildings or work areas to prevent airborne particulate.
- Landscaping or planting of vegetation.
- Confining abrasive blasting where possible.
- Other techniques, as necessary"

Table 4.5-1
Available Fugitive Dust Control Methods for
Disturbed Surface Areas

Control Method	Description/Remarks
Work Practice Controls	Paving identified roads and access points early in the construction process, phasing of earth moving activities to reduce disturbed surface extent, compaction and/or stabilization of disturbed surfaces as quickly as practical. Onsite traffic control program to direct, control, and restrict unnecessary traffic.
Watering	Use of water or water plus a wetting agent to suppress fugitive dust over disturbed areas. Typically applied with spray nozzles attached to a special truck adapted for this purpose. Temporary in nature, but cost-effective even with frequent reapplication.
Graveling	Graveling of high volume traffic areas within the disturbed area of the construction site provides a physical stabilization of the exposed surface and covers the surface with a material having a lower silt content.
Wind Fencing	Wind fencing provides a sheltered region behind the fence line which reduces the mechanical turbulence generated by the ambient winds. The sheltered area of dust control is proportional to the physical height of the fence around the disturbed surface.
Physical Stabilization	Physical stabilization methods involve the application of materials such as rock, bark, wood chips, straw, or other suitable materials to cover the exposed surface, thus preventing the wind from disturbing the surface particles. Graveling is one example of physical stabilization.
Vegetative Stabilization	Vegetative cover provides a physical stabilization and wind shelter of the disturbed surface. However, it is effective only on inactive areas of the disturbed surfaces where frequent mechanical (i.e., earth moving) activities are not anticipated. As such, it is typically not implemented during short-term construction activities.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities do not warrant their use as they are not cost-effective over such a small scale of application and reapplication.

Table 4.5-2
Available Fugitive Dust Control Methods for
Storage Piles

Control Method	Description/Remarks
Work Practice Controls	Minimize temporary material storage pile(s) size and number by utilizing phased earth moving activities. Minimized drop height when adding material to the pile(s), and perform loading and unloading operations on the leeward (down wind) side of the pile. Cleanup spillage and maintain material to the confines of the pile.
Watering	Use of water or water plus a wetting agent to suppress fugitive dust from the storage pile. Temporary in nature, but cost-effective even with frequent reapplication.
Wind Fencing/ Barriers	Wind fencing or partial temporary barriers or enclosures provides a sheltered region in the vicinity of the storage pile which reduces the mechanical turbulence generated by the ambient winds. The sheltered area of dust control is proportional to the physical height of the fence or barrier.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities do not warrant their use as they are not cost-effective over such a small scale of application and reapplication.

Table 4.5-3
Available Fugitive Dust Control Methods for
Earth Moving

Control Method	Description/Remarks
Work Practice Controls	Onsite traffic control program to direct, control speed, and restrict unnecessary traffic. Reduce offsite hauling with balanced cut and fill operations and construction management. Cover truck beds during material hauling operations.
Watering	Preapplication of water or water plus a wetting agent to suppress fugitive dust prior to, and to the extent possible, during earth moving operations. Temporary in nature, but cost-effective even with frequent reapplication.
Wheel Washing	Water washing of heavy construction equipment wheels and undercarriages at construction site egress points to prevent material trackout and deposition outside of the construction site. System may include automatic or manual sprayers, and/or drive-though wheel washing basins.
Wind Fencing/ Barriers	Wind fencing or partial temporary barriers or enclosures provides a sheltered region in the vicinity of the storage pile which reduces the mechanical turbulence generated by the ambient winds. The sheltered area of dust control is proportional to the physical height of the fence or barrier.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities do not warrant their use as they are not cost-effective over such a small scale of application and reapplication.

Table 4.5-4
Available Fugitive Dust Control Methods for
Vehicular Traffic

Control Method	Description/Remarks
Work Practice Controls	Onsite traffic control program to direct, control speed, and restrict unnecessary traffic. Reduce offsite hauling with balanced cut and fill operations and construction management. Cover truck beds during material hauling operations.
Watering	UNPAVED ROADS Application of water or water plus a wetting agent to suppress fugitive dust prior to, and to the extent possible, during earth moving operations. Temporary in nature, but cost-effective even with frequent reapplication.
Graveling	Graveling of high volume unpaved traffic areas provides a physical stabilization of the exposed surface and covers the surface with a material having a lower silt content.
Chemical Stabilization	Chemical stabilization is a dust suppressant method that uses binding agents that, upon application, bind the surface particles to form a protective crust over the disturbed surface. Typically, the temporary nature of construction activities do not warrant their use as they are not cost-effective over such a small scale of application and reapplication.

Attachment M
Risk Management Plan

EPA United States Environmental Protection Agency

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460
OFFICE OF SOLID WASTE AND EMERGENCY RESPONSE

Ashley Jansen
Southern Company- Florida, LLC
One Energy Place
Pensacola, FL 32520-0328

June 03, 2003

EPA Facility ID#: **1000 0018 2713**
Postmark Date: **05/19/2003**
Anniversary Date: **05/19/2008**

NOTIFICATION LETTER: COMPLETE RMP

The U.S. Environmental Protection Agency (EPA) received your Risk Management Plan (RMP) dated with the above postmark date. **This letter notifies you that your RMP is "complete" according to EPA's completion check.** The completion check is a program implemented by EPA to determine whether a submitted RMP includes the minimum amount of information every RMP must provide. The completion check does not assess whether a submitted RMP should have provided additional information or whether the information it provides is accurate or appropriate. In other words, it does not indicate that the RMP meets the requirements of 40 CFR Part 68.

Please note the anniversary date indicated above. Your RMP must be revised and updated by this date or earlier as required by 40 CFR §68.190. Please also note your EPA Facility ID number as identified at the top of this letter; all future Risk Management Plan submissions, corrections and other correspondence must include this number.

Your RMP (excluding the Offsite Consequence Analysis data) can be viewed on RMP*Info™, a national database on the Internet at http://www.epa.gov/enviro.

□

RMP Validation Errors/Warnings for Facility: Curtis H. Stanton Energy Center Unit A

RECORD ERRORS

Section / Record /Name	Error Type	Error Message
S1 Facility Registration		
1		
1.12.c Clear Air Operating Permit	WARNING	If you have a permit number, you should enter it.

One Energy Place
Pensacola, Florida 32520

Tel 850.444.6111

GULF POWER
A SOUTHERN COMPANY

June 26, 2003

RMP Reporting Center
c/o CSC, Inc., Suite 500
8400 Corporate Drive
Landover, Maryland 20785
Attention: Risk Management Plans

RE: Curtis H. Stanton Energy Center Unit A: EPA Facility ID #1000 0018 2713

Sir/Madam:

The Curtis H. Stanton Energy Center Unit A has two processes that are covered under the Risk Management Program (RMP) regulations, 40 CFR Part 68, as Program 3 processes. An RMP report for the chlorine system was submitted on May 19, 2003. The enclosed RMP submittal has been updated to include anhydrous ammonia. Anhydrous ammonia will be stored on-site in one 18,000 gallon tank for use as part of the Selective Catalytic Reductions system. Please also note that the facility address has been revised.

If you have any questions regarding this information, please contact Ashley Jansen at (850) 444-6141.

Sincerely,

James O. Vick
Manager, Environmental Affairs

cc: Ashley Jansen
J.A. Tucker
Heather Turner
Ronnie Walston
Dwain Waters

RMP Report for Curtis H. Stanton Energy Center Unit A

Section 1. Registration Information

1.1 Source Identification: **Facility ID:** 4 There were no reportable accidents in the last 5 years.

a. Facility Name: Curtis H. Stanton Energy Center Unit A

b. Parent Company #1 Name: Southern Company- Florida, LLC

c. Parent Company #2 Name: Orlando Utilities Commission

1.2 EPA Facility Identifier: 1000 0018 2713

1.3 Other EPA Systems Facility ID

1.4 Dun and Bradstreet Numbers (DUNS):

a. Facility DUNS:

b. Parent Company #1 DUNS: 101058100

c. Parent Company #2 DUNS: 004076071

1.5 Facility Location Address:

a. Street 1: 5150 South Alafaya Trail

b. Street 2:

c. City: Orlando **d. State:** FL **e. Zip:** 32831 -

f. County: Orange

Facility Latitude and Longitude:

g. Lat. (ddmmss.s): 28 29 18.0 **h. Long. (dddmmss.s):** -081 10 01.3

i. Lat/Long Method: UN Unknown

j. Lat/Long Description: CE Center of Facility

1.6 Owner or Operator:

a. Name: Southern Company- Florida, LLC

b. Phone: (850) 444-6141

Mailing address:

c. Street 1: One Energy Place **d. Street 2:**

e. City: Pensacola **f. State:** FL **g. Zip:** 32520 -0328

1.7 Name and title of person or position responsible for part 68 (RMP) implementation:

a. Name of person: Ashley Jansen

b. Title of person or position: Engineer

1.8 Emergency contact:

a. Name: Heather Turner

b. Title: Compliance Specialist Sr

c. Phone: (321) 235-2593

d. 24-hour phone: (407) 970-1606

e. Ext. or PIN:

1.9 Other points of contact:

a. Facility or Parent Company E-Mail Address:

b. Facility Public Contact Phone:

c. Facility or Parent Company WWW Homepage Address:

1.10 LEPC: District 6 LEPC

1.11 Number of full time employees on s 21

1.12 Covered by:

a. OSHA PSM: Yes

b. EPCRA 302: Yes

c. CAA Title V: Yes **Air operating permit ID:**

1.13 OSHA Star or Merit Ranking: No

1.14 Last Safety Inspection (by an External Agency) Date:

1.15 Last Safety Inspection Performed by an External Agency: Never had one

1.16 Will this RMP involve predictive filing?: No

Section 1.17 Process(es)

a. Process ID: 5 **Program Level** 3 Chlorine Process

b. NAICS Code

22131 Water Supply and Irrigation Systems

c. Process Chemicals

c.1 Process Chemical (ID / Name)	c.2 CAS Nr.	c.3 Qty (lbs.)

6	Chlorine	7782-50-5	12,000

a. Process ID: 6 Program Level 3 Anhydrous Ammonia

b. NAICS Code

22111 Electric Power Generation

c. Process Chemicals

c.1 Process Chemical (ID / Name)	c.2 CAS Nr.	c.3 Qty (lbs.)
7 Ammonia (anhydrous)	7664-41-7	80,789

Section 2. Toxics: Worst Case

Toxics: Worst Case ID 9

2.1 a. Chemical Name: Chlorine

b. Percent Weight of Chemical (if in a mixture):

2.2 Physical State: Gas Liquified by Pressure

2.3 Model used: EPA's RMP *Comp(TM)

2.4 Scenario: Gas Release

2.5 Quantity released: 2,000 lbs

2.6 Release rate: 200.0 lbs/min

2.7 Release duration: 10.0 mins

2.8 Wind speed: 1.5 m/sec

2.9 Atmospheric Stability Class: F

2.10 Topography: Rural

2.11 Distance to Endpoint: 3.00 mi

2.12 Estimated Residential population within distance to endpoint: 5,100

2.13 Public receptors within distance to endpoint:

a. Schools:	Yes	d. Prisons/Correction facilities:	Yes
b. Residences:	Yes	e. Recreation areas:	Yes
c. Hospitals:	No	f. Major commercial, office or, industrial areas:	Yes
g. Other (Specify):			

2.14 Environmental receptors within distance to endpoint:

a. National or state parks, forests, or monuments:	No
b. Officially designated wildlife sanctuaries, preserves, or refuges:	No
c. Federal wilderness areas:	No
d. Other (Specify):	

2.15 Passive mitigation considered:

a. Dikes:	No	d. Drains:	No

b. Enclosures: No **e. Sumps:** No

c. Berms: No **f. Other (Specify):**

2.16 Graphic file name:

Toxics: Worst Case ID 10

2.1 a. Chemical Name: Ammonia (anhydrous)

b. Percent Weight of Chemical (if in a mixture):

2.2 Physical State: Gas Liquified by Pressure

2.3 Model used: DEGADIS

2.4 Scenario: Gas Release

2.5 Quantity released: 80,789 **lbs**

2.6 Release rate: 8,078.9 **lbs/min**

2.7 Release duration: 10.0 **mins**

2.8 Wind speed: 1.5 **m/sec**

2.9 Atmospheric Stability Class: F

2.10 Topography: Rural

2.11 Distance to Endpoint: 2.11 **mi**

2.12 Estimated Residential population within distance to endpoint: 2,300

2.13 Public receptors within distance to endpoint:

a. Schools: Yes **d. Prisons/Correction facilities:** Yes

b. Residences: Yes **e. Recreation areas:** Yes

c. Hospitals: No **f. Major commercial, office or, industrial areas:** Yes

g. Other (Specify):

2.14 Environmental receptors within distance to endpoint:

a. National or state parks, forests, or monuments: No

b. Officially designated wildlife sanctuaries, preserves, or refuges: No

c. Federal wilderness areas: No

d. Other (Specify):

2.15 Passive mitigation considered:

a. Dikes: No **d. Drains:** No

b. Enclosures: No **e. Sumps:** No

c. Berms: No **f. Other (Specify):**

2.16 Graphic file name:

Section 3. Toxics: Alternative Release

Toxics: Alternative Release ID: 8

3.1 a. Chemical Name: Chlorine

b. Percent Weight of Chemical (if in a mixture):

3.2 Physical State: Gas Liquified by Pressure

3.3 Model: EPA's RMP *Comp(TM)

3.4 Scenario: Valve failure resulting in a 0.75" rupture

3.5 Quantity released: 9,114 **lbs**

3.6 Release rate: 151.9 **lbs/min**

3.7 Release duration: 60.0 **mins**

3.8 Wind speed: 3.0 **m/sec**

3.9 Atmospheric Stability Class: D

3.10 Topography: Rural

3.11 Distance to Endpoint: 0.60 **mi**

3.12 Estimated Residential population within distance to endpoint: 205

3.13 Public receptors within distance to endpoint:

a. Schools:	No	**d. Prisons/Correction facilities:**	No
b. Residences:	No	**e. Recreation areas:**	No
c. Hospitals:	No	**f. Major commercial, office, or industrial areas:**	Yes

g. Other (Specify):

3.14 Environmental receptors within distance to endpoint:

a. National or state parks, forests, or monuments:	No
b. Officially designated wildlife sanctuaries, preserves, or refuges:	No
c. Federal wilderness areas:	No

d. Other (Specify):

3.15 Passive mitigation considered:

a. Dikes:	No	**d. Drains:**	No
b. Enclosures:	No	**e. Sumps:**	No
c. Berms:	No	**f. Other (Specify):**	

3.16 Active mitigation considered:

a. Sprinkler systems:	No	**f. Flares:**	No
b. Deluge system:	No	**g. Scrubbers:**	No
c. Water curtain:	No	**h. Emergency shutdown systems:**	No
d. Neutralization:	No	**i. Other (Specify):**	
e. Excess flow valve:	No		

3.17 Graphic file name:

Toxics: Alternative Release ID: 9

3.1 a. Chemical Name: Ammonia (anhydrous)

b. Percent Weight of Chemical (if in a mixture):

3.2 Physical State: Gas Liquified by Pressure

3.3 Model: INPUFF

3.4 Scenario: Rupture disk/Relief Valve failure

3.5 Quantity released: 33,333 **lbs**

3.6 Release rate: 555.6 **lbs/min**

3.7 Release duration: 60.0 **mins**

3.8 Wind speed: 3.0 **m/sec**

3.9 Atmospheric Stability Class: D

3.10 Topography: Rural

3.11 Distance to Endpoint: 0.12 **mi**

3.12 Estimated Residential population within distance to endpoint: 10

3.13 Public receptors within distance to endpoint:

a. Schools:	No	**d. Prisons/Correction facilities:**	No
b. Residences:	No	**e. Recreation areas:**	No
c. Hospitals:	No	**f. Major commercial, office, or industrial areas:**	No

g. Other (Specify): guard office

3.14 Environmental receptors within distance to endpoint:

a. National or state parks, forests, or monuments:	No
b. Officially designated wildlife sanctuaries, preserves, or refuges:	No
c. Federal wilderness areas:	No

d. Other (Specify):

3.15 Passive mitigation considered:

a. Dikes:	No	**d. Drains:**	No
b. Enclosures:	No	**e. Sumps:**	No
c. Berms:	No	**f. Other (Specify):**	

3.16 Active mitigation considered:

a. Sprinkler systems:	No	**f. Flares:**	No
b. Deluge system:	No	**g. Scrubbers:**	No
c. Water curtain:	No	**h. Emergency shutdown systems:**	No
d. Neutralization:	No	**i. Other (Specify):**	
e. Excess flow valve:	No		

3.17 Graphic file name:

Section 4. Flammables: Worst Case --- No Data To Report

Section 5. Flammables: Alternative Release --- No Data To Report

Section 6. Accident History --- No Data To Report

Section 7. Prevention Program 3

Process ID: 5 Chlorine Process

Prevention Program ID: 6

Prevention Program Description: Chlorine Process

7.1 NAICS Code 22131

7.2 Chemicals

Chemical Name
Chlorine

7.3 Date on which the safety information was last reviewed or revised: 05/15/2003

7.4 Process Hazard Analysis (PHA):

a. Date of last PHA or PHA update: 03/11/2003

b. The technique used:

What If:	Yes	**Failure Mode and Effects Analysis:**	No
Checklist:	No	**Fault Tree Analysis:**	No
What If/Checklist:	No	**Other (Specify):**	
HAZOP:	Yes		

c. Expected or actual date of completion of all changes from last PHA or PHA update: 08/01/2004

d. Major hazards identified:

Toxic release:	Yes	**Contamination:**	No
Fire:	No	**Equipment failure:**	Yes
Explosion:	No	**Loss of cooling, heating, electricity, instrument air:**	No
Runaway reaction:	No	**Earthquake:**	No
Polymerization:	No	**Floods (flood plain):**	No
Overpressurization:	No	**Tornado:**	Yes
Corrosion:	Yes	**Hurricanes:**	Yes
Overfilling:	No	**Other (Specify):**	

e. Process controls in use:

Vents:	No	**Emergency air supply:**	No
Relief valves:	No	**Emergency power:**	Yes

Check valves:	Yes	**Backup pump:**	No
Scrubbers:	No	**Grounding equipment:**	No
Flares:	No	**Inhibitor addition:**	No
Manual shutoffs:	Yes	**Rupture disks:**	No
Automatic shutoffs:	Yes	**Excess flow device:**	No
Interlocks:	Yes	**Quench system:**	No
Alarms and procedures:	Yes	**Purge system:**	No
Keyed bypass:	No	**None:**	No
		Other (Specify):	

f. Mitigation systems in use:

Sprinkler system:	No	**Water curtain:**	No
Dikes:	No	**Enclosure:**	No
Fire walls:	No	**Neutralization:**	No
Blast walls:	No	**None:**	Yes
Deluge system:	No	**Other (Specify):**	

g. Monitoring/detection systems in use:

Process area detectors:	Yes	**None:**	No
Perimeter monitors:	No	**Other (Specify):**	

h. Changes since last PHA or PHA update:

Reduction in chemical inventory:	No	**Installation of perimeter monitoring systems:**	No
Increase in chemical inventory:	No	**Installation of mitigation systems:**	No
Change process parameters:	No	**None recommended:**	No
Installation of process controls:	No	**None:**	Yes
Installation of process detection systems:	No	**Other (Specify):**	

7.5 Date of most recent review or revision of operating procedures: 05/15/2003

7.6 Training:

a. The date of the most recent review or revision of training programs: 05/15/2003

b. The type of training provided:

Classroom: Yes **On the job:** No **Other (Specify):**

c. The type of competency testing used:

Written test:	No	**Observation:**	Yes
Oral test:	No	**Other (Specify):**	
Demonstration:	No		

7.7 Maintenance:

a. The date of the most recent review or revision of maintenance procedures: 05/16/2003

b. The date of the most recent equipment inspection or test: 05/19/2003

c. Equipment most recently inspected or tested : flexible connections and valves

7.8 Management of change:

a. The date of the most recent change that triggered management of change procedures: 05/15/2003

b. The date of the most recent review or revision of management of change procedures: 05/15/2003

7.9 The date of the most recent pre-startup review: 05/15/2003

7.10 Compliance audits:

a. The date of the most recent compliance audit:

b. Expected date of completion of all changes resulting from the compliance audit:

7.11 Incident investigation:

a. The date of the most recent incident investigation (if any):

b. Expected or actual date of completion of all changes resulting from the investigation:

7.12 The date of the most recent review or revision of employee participation plans: 05/15/2003

7.13 The date of the most recent review or revision of hot work permit procedures: 05/13/2003

7.14 The date of the most recent review or revision of contractor safety procedures: 05/13/2003

7.15 The date of the most recent evaluation of contractor safety performance: 05/13/2003

Process ID: 6 Anhydrous Ammonia

Prevention Program ID: 7

Prevention Program Description: Anhydrous Ammonia

7.1 NAICS Code 22111

7.2 Chemicals

Chemical Name
Ammonia (anhydrous)

7.3 Date on which the safety information was last reviewed or revised: 06/24/2003

7.4 Process Hazard Analysis (PHA):

a. Date of last PHA or PHA update: 03/11/2003

b. The technique used:

What If:	Yes	**Failure Mode and Effects Analysis:**	No
Checklist:	No	**Fault Tree Analysis:**	No
What If/Checklist:	No	**Other (Specify):**	
HAZOP:	Yes		

c. Expected or actual date of completion of all changes from last PHA or PHA update:

d. Major hazards identified:

Toxic release:	Yes	**Contamination:**	No
Fire:	No	**Equipment failure:**	Yes
Explosion:	No	**Loss of cooling, heating, electricity, instrument air:**	No
Runaway reaction:	No	**Earthquake:**	No
Polymerization:	No	**Floods (flood plain):**	No
Overpressurization:	No	**Tornado:**	No
Corrosion:	Yes	**Hurricanes:**	No
Overfilling:	No	**Other (Specify):**	

e. Process controls in use:

Vents:	No	**Emergency air supply:**	No
Relief valves:	Yes	**Emergency power:**	Yes
Check valves:	Yes	**Backup pump:**	Yes
Scrubbers:	No	**Grounding equipment:**	Yes
Flares:	No	**Inhibitor addition:**	No
Manual shutoffs:	Yes	**Rupture disks:**	No
Automatic shutoffs:	No	**Excess flow device:**	No
Interlocks:	No	**Quench system:**	No
Alarms and procedures:	Yes	**Purge system:**	No
Keyed bypass:	No	**None:**	No
		Other (Specify):	

f. Mitigation systems in use:

Sprinkler system:	No	**Water curtain:**	Yes
Dikes:	No	**Enclosure:**	No
Fire walls:	No	**Neutralization:**	No
Blast walls:	No	**None:**	No
Deluge system:	No	**Other (Specify):**	

g. Monitoring/detection systems in use:

Process area detectors:	Yes	**None:**	No
Perimeter monitors:	No	**Other (Specify):**	

h. Changes since last PHA or PHA update:

Reduction in chemical inventory:	No	**Installation of perimeter monitoring systems:**	No
Increase in chemical inventory:	No	**Installation of mitigation systems:**	No

Change process parameters:	No	**None recommended:**	No
Installation of process controls:	No	**None:**	Yes
Installation of process detection systems:	No	**Other (Specify):**	

7.5 Date of most recent review or revision of operating procedures: 06/25/2003

7.6 Training:

a. The date of the most recent review or revision of training programs: 05/15/2003

b. The type of training provided:

Classroom: Yes **On the job:** No **Other (Specify):**

c. The type of competency testing used:

Written test:	No	**Observation:**	Yes
Oral test:	No	**Other (Specify):**	
Demonstration:	No		

7.7 Maintenance:

a. The date of the most recent review or revision of maintenance procedures: 06/24/2003

b. The date of the most recent equipment inspection or test: 06/24/2003

c. Equipment most recently inspected or tested : ammonia sensors

7.8 Management of change:

a. The date of the most recent change that triggered management of change procedures: 05/15/2003

b. The date of the most recent review or revision of management of change procedures: 06/23/2003

7.9 The date of the most recent pre-startup review: 06/26/2003

7.10 Compliance audits:

a. The date of the most recent compliance audit:

b. Expected date of completion of all changes resulting from the compliance audit:

7.11 Incident investigation:

a. The date of the most recent incident investigation (if any):

b. Expected or actual date of completion of all changes resulting from the investigation:

7.12 The date of the most recent review or revision of employee participation plans: 05/15/2003

7.13 The date of the most recent review or revision of hot work permit procedures: 05/15/2003

7.14 The date of the most recent review or revision of contractor safety procedures: 05/15/2003

7.15 The date of the most recent evaluation of contractor safety performance: 05/15/2003

Section 8. Prevention Program 2 --- No Data To Report

Section 9. Emergency Response

9.1 Written Emergency Response (ER) Plan:

a. Is facility included in written community emergency response plan?	No
b. Does facility have its own written emergency response plan?	Yes
9.2 Does facility's ER plan include specific actions to be taken in response to accidental releases of regulated substance(s)?	Yes
9.3 Does facility's ER plan include procedures for informing the public and local agencies responding to accidental releases?	Yes
9.4 Does facility's ER plan include information on emergency heath care?	Yes
9.5 Date of most recent review or update of facility's ER plan:	05/15/2003
9.6 Date of most recent ER training for facility's employees:	05/15/2003

9.7 Local agency with which facility's ER plan or response activities are coordinated:

a. Name of agency:	Orange County Fire Department
b. Telephone number:	(407) 249-4555

9.8 Subject to:

a. OSHA Regulations at 29 CFR 1910.38:	Yes
b. OSHA Regulations at 29 CFR 1910.120:	Yes
c. Clean Water Act Regulations at 40 CFR 112:	Yes
d. RCRA Regulations at 40 CFR 264, 265, and 279.52:	No
e. OPA-90 Regulations at 40 CFR 112, 33 CFR 154, 49 CFR 194, or 30 CFR 254:	Yes
f. State EPCRA Rules/Law:	Yes
g. Other (Specify):	

Executive Summary

The Curtis H. Stanton Energy Center located at 5150 South Alafaya Trail in Orlando, Orange County, Florida, has two coal fired operating units. A combined cycled operating unit, Stanton Unit A, is currently under construction north of the existing units. Stanton Unit A is scheduled to begin commercial operation in October 2003 as a 633 MW facility. Stanton Unit A is jointly owned by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency, and Southern Company-Florida. The new unit will be operated by Southern Company-Florida.

Employee safety and health is a fundamental value of Southern Company-Florida. It is the policy of the facility to provide and maintain safe working conditions and to operate and manage facilities in a manner that protects the environment and meets or surpasses all federal, state, and local environmental regulations. Stanton Unit A has a safety program designed to ensure that employees' and contractors' are working in a safe environment. The program includes training, operating and maintenance procedures, as well as an auditing and incident investigation programs.

Stanton Unit A will have two processes that are covered under the Risk Management Program (RMP) regulations, 40 CFR Part 68, as Program 3 processes. Anhydrous ammonia will be stored on-site in one 18,000 gallon tank for use as part of the Selective Catalytic Reductions system used to control nitrogen oxide emissions generated from burning natural gas. The facility will use chlorine as a biocide to treat the cooling water.

The worst case chlorine release scenario was defined as the release of the largest single vessel occurring over ten minutes. The RMP*COMP version 1.07 model predicted that the chlorine gas would travel 3.0 miles before it reached its endpoint. The 2000 Census data predicted that 5,100 people would be affected by a worst case chlorine release. A valve failure resulting in a 0.75" rupture was used for the alternative case scenario. The model predicted that at a release rate of 151.9 lb/min the chlorine would travel 0.6 miles before it reached its endpoint. This alternative release scenario would affect approximately 205 people.

The worst case ammonia release scenario predicted that 2,300 people would be affected by ammonia concentrations greater than the toxic endpoint. This modeling was conducted assuming that the entire content of the vessel was released in ten minutes. A pressure relief valve failure resulting in a release rate of 555.6 lb/min occurring for sixty minutes was used for the alternative release case scenario. The model predicted that ammonia would travel 0.12 miles before reaching its toxic endpoint. This would affect approximately ten people.

Stanton Unit A has developed an emergency response plan that complies with 29 CFR 1910.38 to protect the public health and the environment. This plan includes procedures for notifying the public about accidental releases, procedures for the use and maintenance of response equipment, employee training, and procedures to review and update the plan. The Orange County Fire Department has visited the site and been made aware of the facility's emergency response procedures. Emergency notification will be made by dialing 911 to notify the Orange County Fire Department Haz-Mat

RMP Validation Errors/Warnings for Facility: Curtis H. Stanton Energy Center Unit A

RECORD ERRORS

Section / Record /Name	Error Type	Error Message
S1 Facility Registration		
4		
1.12.c Clear Air Operating Permit	WARNING	If you have a permit number, you should enter it.

Certification Statement

To the best of the undersigned's knowledge, information, and belief formed after reasonable inquiry, the information submitted is true, accurate, and complete.

Curtis H. Stanton Energy Center's RMP Submittal.

James O Vick

Signature

James O. Vick

Print Name

Manager, Environmental Affairs

Title

June 26, 2003

Date

Attachment N
Potential to Emit, Enveloped Spreadsheet, and HAPs Analysis

Table 2
Annual Emission Rates

Cases[d]	No. of CCCT/HRSGs	Annual Operation (hrs/yr)	Emission Rates									
			NO_x		CO		PM/PM_{10}		SO_2		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
4, 8, 8, 4, 8	2	6,760[a]	60.76	205.37	194.26	656.60	23.24	78.55	7.00	23.66	22.76	76.93
18, 18, 18, 18, 18	2	1,000[b]	58.84	29.42	285.02	142.51	23.42	11.71	6.78	3.39	40.26	20.13
20, 20, 20, 20 ,20	2	1,000[c]	159.38	79.69	142.00	71.00	34.00	17.00	214.00	107.00	16.00	8.00
Totals	2	8,760	N/A	314.48	N/A	870.11	N/A	107.26	N/A	134.05	N/A	105.06

[a]Assumes operation on natural gas (including duct burning) for 6,760 hour per year at 100% load.
[b]Assumes operation on natural gas (including duct burning and power augmentation) for 1,000 hours per year at 100% load.
[c]Assumes operation on distillate fuel oil for 1,000 hours per year at 100% load.
[d]Cases are listed respectively for the pollutants as they are listed across the top of the table.

Table 1
Hourly Emission Rates (Per CCCT/HRSG)

Case	Ambient Temperature (°F)	Load (%)	NOx (lb/hr)	CO (lb/hr)	PM/PM_{10} (lb/hr)	SO_2 (lb/hr)	VOC (lb/hr)
Natural Gas							
1	19	100	24.13	31.00	9.00	2.77	3.00
2	19	75	19.23	25.00	9.00	2.23	2.40
3	19	50	15.18	20.00	9.00	1.78	2.00
4	19	100	30.38	75.90	11.49	3.50	10.98
5	45	100	23.21	50.00	9.00	2.67	3.00
6	45	75	18.54	40.00	9.00	2.15	2.40
7	45	50	14.70	33.00	9.00	1.73	2.00
8	45	100	29.76	97.13	11.62	3.43	11.38
9	60	100	29.04	129.50	11.26	3.35	17.49
10	70	100	22.26	48.00	9.00	2.56	2.80
11	70	75	17.86	38.00	9.00	2.07	2.20
12	70	50	14.15	32.00	9.00	1.66	1.80
13	70	100	27.76	87.51	11.20	3.20	9.82
14	95	100	21.47	45.00	9.00	2.47	2.80
15	95	75	17.29	38.00	9.00	2.01	2.20
16	95	50	13.65	32.00	9.00	1.60	1.80
17	95	100	28.56	130.12	11.36	3.29	17.93
18	95	100	29.42	142.51	11.71	3.39	20.13
19	95	100	26.63	82.14	11.06	3.07	9.40
Maximum Emission Rate			30.38	142.51	11.71	3.50	20.13
Distillate Fuel Oil							
20	19	100	79.69	71.00	17.00	107.00	8.00
21	19	75	63.58	59.00	17.00	86.00	6.00
22	19	50	49.27	66.00	17.00	68.00	5.00
23	45	100	76.70	67.00	17.00	103.00	7.50
24	70	100	73.70	64.00	17.00	99.00	7.00
25	95	100	71.01	61.00	17.00	96.00	7.00
Maximum Emission Rate			79.69	71.00	17.00	107.00	8.00

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Enveloped Representative Pollutant Emission and Stack Parameters

Combined Cycle Operation - Natural Gas

NOTE Ref. 01/16/01 performance data.

Load 100 percent **GE7FA**

Case Name	Case 1	Case 4	Case 5	Case 8	Case 9	Case 10	Case 13	Case 14	Case 17	Case 18	Case 19
Ambient Temp (F)	19	19	45	45	60	70	70	95	95	95	95
Evap Cooler					X	X	X	X	X	X	X
Power Aug. (Steam Inj.)					X				X	X	
Exit Temp (F)	185	178	181	175	178	178	172	176	169	168	170
Exit Velocity (ft/s)	62.29	62.21	59.49	59.55	61.00	56.85	56.84	54.98	57.87	57.85	54.94
Emissions (lb/h)											
NOX (e)	24.13	30.38	23.21	29.76	29.04	22.26	27.76	21.47	28.56	29.42	26.63
CO	31.00	75.90	50.00	97.13	129.50	48.00	87.51	45.00	130.12	142.51	82.14
PM/PM10	9.00	11.49	9.00	11.62	11.26	9.00	11.20	9.00	11.36	11.71	11.06
SO2 (c)	2.77	3.50	2.67	3.43	3.35	2.56	3.20	2.47	3.29	3.39	3.07
VOC	3.00	10.98	3.00	11.38	17.49	2.80	9.82	2.80	17.93	20.13	9.40

Load 75 percent

Case Name	Case 2	Case 6	Case 11	Case 15
Ambient Temp (F)	19	45	70	95
Evap Cooler				
Power Aug. (Steam Inj.)				
Exit Temp (F)	170	170	168	166
Exit Velocity (ft/s)	47.55	46.38	45.16	44.25
Emissions (lb/h)				
NOX (e)	19.23	18.54	17.86	17.29
CO	25.00	40.00	38.00	38.00
PM/PM10	9.00	9.00	9.00	9.00
SO2 (c)	2.23	2.15	2.07	2.01
VOC	2.40	2.40	2.20	2.20

Load 50 percent

Case Name	Case 3	Case 7	Case 12	Case 16
Ambient Temp (F)	19	45	70	95
Evap Cooler				
Power Aug. (Steam Inj.)				
Exit Temp (F)	157	160	160	160
Exit Velocity (ft/s)	38.14	37.60	37.06	36.71
Emissions (lb/h)				
NOX (e)	15.18	14.70	14.15	13.65
CO	20.00	33.00	32.00	32.00
PM/PM10	9.00	9.00	9.00	9.00
SO2 (c)	1.78	1.73	1.66	1.60
VOC	2.00	2.00	1.80	1.80

Enveloped Load Representative Emissions and Stack Parameters

Exit Temp (F)	168.00	348.71	K
Exit Velocity (ft/s)	54.94	16.75	m/s
Emissions (lb/h)			
NOX	30.38	3.83	g/s
CO	142.51	17.96	g/s
PM/PM10	11.71	1.48	g/s
SO2	3.50	0.44	g/s
VOC	20.13	2.54	g/s

Exit Temp (F)	166.00	347.59	K
Exit Velocity (ft/s)	44.25	13.49	m/s
Emissions (lb/h)			
NOX	19.23	2.42	g/s
CO	40.00	5.04	g/s
PM/PM10	9.00	1.13	g/s
SO2	2.23	0.28	g/s
VOC	2.40	0.30	g/s

Exit Temp (F)	157.00	342.59	K
Exit Velocity (ft/s)	36.71	11.19	m/s
Emissions (lb/h)			
NOX	15.18	1.91	g/s
CO	33.00	4.16	g/s
PM/PM10	9.00	1.13	g/s
SO2	1.78	0.22	g/s
VOC	2.00	0.25	g/s

Combined Cycle Operation - Fuel Oil

NOTE Ref. 01/16/01 performance data.

Load 100 percent **GE7FA**

Case Name	Case 20	Case 23	Case 24	Case 25
Ambient Temp (F)	19	45	70	95
Evap Cooler			X	X
Power Aug. (Steam Inj.)				
Exit Temp (F)	287	281	276	272
Exit Velocity (ft/s)	75.25	71.45	67.9	65.28
Emissions (lb/h)				
NOX(e)	79.69	76.70	73.70	71.01
CO	71.00	67.00	64.00	61.00
PM/PM10	17.00	17.00	17.00	17.00
SO2 (d)	107.00	103.00	99.00	96.00
VOC	8.00	7.50	7.00	7.00

Case Name	Case 21
Ambient Temp (F)	19
Evap Cooler	
Power Aug. (Steam Inj.)	
Exit Temp (F)	262
Exit Velocity (ft/s)	55.57
Emissions (lb/h)	
NOX(e)	63.58
CO	59.00
PM/PM10	17.00
SO2 (d)	86.00
VOC	6.00

Case Name	Case 22
Ambient Temp (F)	19
Evap Cooler	
Power Aug. (Steam Inj.)	
Exit Temp (F)	249
Exit Velocity (ft/s)	43.90
Emissions (lb/h)	
NOX(e)	49.27
CO	66.00
PM/PM10	17.00
SO2 (d)	68.00
VOC	5.00

Enveloped Load Representative Emissions and Stack Parameters

Exit Temp (F)	272.00	406.48	K
Exit Velocity (ft/s)	65.28	19.90	m/s
Emissions (lb/h)			
NOX	79.69	10.04	g/s
CO	71.00	8.95	g/s
PM/PM10	17.00	2.14	g/s
SO2	107.00	13.48	g/s
VOC	8.00	1.01	g/s

Exit Temp (F)	262.00	400.93	K
Exit Velocity (ft/s)	55.57	16.94	m/s
Emissions (lb/h)			
NOX	63.58	8.01	g/s
CO	59.00	7.43	g/s
PM/PM10	17.00	2.14	g/s
SO2	86.00	10.84	g/s
VOC	6.00	0.76	g/s

Exit Temp (F)	249.00	393.71	K
Exit Velocity (ft/s)	43.90	13.38	m/s
Emissions (lb/h)			
NOX	49.27	6.21	g/s
CO	66.00	8.32	g/s
PM/PM10	17.00	2.14	g/s
SO2	68.00	8.57	g/s
VOC	5.00	0.63	g/s

Notes

a Combined Total Reduced Sulfur Compounds (including H2S) and Total Reduced Sulfur (including H2S)
b H2SO4 based on a 10% conversion of SO2 to SO3 and a molecular ratio of 1.22 from SO3 to H2SO4 (in the stack and SCR).
c Sulfur content assumed for the Natural Gas = 0.5 grains of sulfur/100 SCF
d Sulfur content assumed for the fuel oil = 0.05% sulfur.
e Natural Gas NOx emissions at 3.5 ppmvd @ 15% O2. Fuel Oil NOx emissions at 10 ppmvd @ 15% O2.
f Assumed 100% conversion of Sulfur to SO2 for natural gas.

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Heat Input

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Combined Cycle Operation - Natural Gas

NOTE Ref: 11/16/01 performance data.

Load 100 percent **GE7FA**

Case Name	Case 1	Case 4	Case 5	Case 8	Case 9	Case 10	Case 13	Case 14	Case 17	Case 18	Case 19
Ambient Temp (F)	19	19	45	45	60	70	70	95	95	95	95
Evap Cooler					X	X	X	X	X	X	X
Power Augmentation (Steam Inj.)					X				X	X	
CTG Heat Input HHV (Btu/hr)	1.90E+09	1.90E+09	1.83E+09	1.83E+09	1.84E+09	1.75E+09	1.75E+09	1.69E+09	1.78E+09	1.78E+09	1.69E+09
Duct Burner Heat Input HHV (Btu/hr)	0	4.99E+08	0	5.24E+08	4.53E+08	0	4.39E+08	0	4.73E+08	5.42E+08	4.13E+08
Total Heat Input HHV (Btu/hr)	1.90E+09	2.40E+09	1.83E+09	2.35E+09	2.30E+09	1.75E+09	2.19E+09	1.69E+09	2.26E+09	2.33E+09	2.11E+09
Fuel Rate (cu ft/hr)	1.94E+06	2.45E+06	1.87E+06	2.40E+06	2.34E+06	1.79E+06	2.24E+06	1.73E+06	2.30E+06	2.37E+06	2.15E+06

Load 75 percent

Case Name	Case 2	Case 6	Case 11	Case 15
Ambient Temp (F)	19	45	70	95
Evap Cooler				
Power Augmentation (Steam Inj.)				
CTG Heat Input HHV (Btu/hr)	1.53E+09	1.48E+09	1.42E+09	1.38E+09
Duct Burner Heat Input HHV (Btu/hr)	0	0	0	0
Total Heat Input HHV (Btu/hr)	1.53E+09	1.48E+09	1.42E+09	1.38E+09
Fuel Rate (cu ft/hr)	1.56E+06	1.51E+06	1.45E+06	1.41E+06

Load 50 percent

Case Name	Case 3	Case 7	Case 12	Case 16
Ambient Temp (F)	19	45	70	95
Evap Cooler				
Power Augmentation (Steam Inj.)				
CTG Heat Input HHV (Btu/hr)	1.22E+09	1.18E+09	1.14E+09	1.10E+09
Duct Burner Heat Input HHV (Btu/hr)	0	0	0	0
Total Heat Input HHV (Btu/hr)	1.22E+09	1.18E+09	1.14E+09	1.10E+09
Fuel Rate (cu ft/hr)	1.25E+06	1.21E+06	1.16E+06	1.12E+06

Combined Cycle Operation - Fuel Oil

NOTE Ref: 11/16/01 performance data.

Load 100 percent **GE7FA**

Case Name	Case 20	Case 23	Case 24	Case 25
Ambient Temp (F)	19	45	70	95
Evap Cooler			X	X
Power Augmentation (Steam Inj.)				
CTG Heat Input HHV (Btu/hr)	2.07E+09	1.99E+09	1.91E+09	1.84E+09
Duct Burner Heat Input HHV (Btu/hr)	0	0	0	0
Total Heat Input HHV (Btu/hr)	2.07E+09	1.99E+09	1.91E+09	1.84E+09
Fuel Rate (gal/hr)	1.44E+04	1.39E+04	1.33E+04	1.29E+04

Case Name	Case 21
Ambient Temp (F)	19
Evap Cooler	
Power Augmentation (Steam Inj.)	
CTG Heat Input HHV (Btu/hr)	1.66E+09
Duct Burner Heat Input HHV (Btu/hr)	0
Total Heat Input HHV (Btu/hr)	1.66E+09
Fuel Rate (gal/hr)	1.16E+04

Case Name	Case 22
Ambient Temp (F)	19
Evap Cooler	
Power Augmentation (Steam Inj.)	
CTG Heat Input HHV (Btu/hr)	1.30E+09
Duct Burner Heat Input HHV (Btu/hr)	0
Total Heat Input HHV (Btu/hr)	1.30E+09
Fuel Rate (gal/hr)	9.10E+03

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Hazardous Air Pollutants

Hazardous Air Pollutants[1]

Duct Burner — Natural Gas

Pollutant	Uncontrolled Emission Factor (lb/10⁶ scf)[2]	Maximum Heat Input (Mbtu/h)	Facility PTE (tpy)[3]
1, 3-Butadiene			
2-Methylnaphthalene	2.40E-05	541.7	1.12E-04
3-Methylchloranthrene	1.80E-06	541.7	8.37E-06
7,12-Dimethylbenz(a)anthracene	1.60E-05	541.7	7.44E-05
Acenaphthene	1.80E-06	541.7	8.37E-06
Acenaphthylene	1.80E-06	541.7	8.37E-06
Acetaldehyde			
Acrolein			
Anthracene	2.40E-06	541.7	1.12E-05
Benz(a)anthracene	1.80E-06	541.7	8.37E-06
Benzene	2.10E-03	541.7	9.77E-03
Benzo(a)pyrene	1.20E-06	541.7	5.58E-06
Benzo(b)fluoranthene	1.80E-06	541.7	8.37E-06
Benzo(g,h,i)perylene	1.20E-06	541.7	5.58E-06
Benzo(k)fluoranthene	1.80E-06	541.7	8.37E-06
Chrysene	1.80E-06	541.7	8.37E-06
Dibenzo(a,h)anthracene	1.20E-06	541.7	5.58E-06
Dichlorobenzene	1.20E-03	541.7	5.58E-03
Ethylbenzene			
Fluoranthene	3.00E-06	541.7	1.40E-05
Fluorene	2.80E-06	541.7	1.30E-05
Formaldehyde	7.50E-02	541.7	3.49E-01
Hexane	1.80E+00	541.7	8.37E+00
Indeno(1,2,3-cd)pyrene	1.80E-06	541.7	8.37E-06
Naphthalene	6.10E-04	541.7	2.84E-03
PAH			
Phenanathrene	1.70E-05	541.7	7.91E-05
Propylene Oxide			
Pyrene	5.00E-06	541.7	2.33E-05
Toluene	3.40E-03	541.7	1.58E-02
Xylenes			
		TOTAL	8.76

Total from Duct Burners

Pollutant	Facility PTE (tpy)
1, 3-Butadiene	
2-Methylnaphthalene	1.12E-04
3-Methylchloranthrene	8.37E-06
7,12-Dimethylbenz(a)anthracene	7.44E-05
Acenaphthene	8.37E-06
Acenaphthylene	8.37E-06
Acetaldehyde	
Acrolein	
Anthracene	1.12E-05
Benz(a)anthracene	8.37E-06
Benzene	9.77E-03
Benzo(a)pyrene	5.58E-06
Benzo(b)fluoranthene	8.37E-06
Benzo(g,h,i)perylene	5.58E-06
Benzo(k)fluoranthene	8.37E-06
Chrysene	8.37E-06
Dibenzo(a,h)anthracene	5.58E-06
Dichlorobenzene	5.58E-03
Ethylbenzene	
Fluoranthene	1.40E-05
Fluorene	1.30E-05
Formaldehyde	3.49E-01
Hexane	8.37E+00
Indeno(1,2,3-cd)pyrene	8.37E-06
Naphthalene	2.84E-03
PAH	
Phenanathrene	7.91E-05
Propylene Oxide	
Pyrene	2.33E-05
Toluene	1.58E-02
Xylenes	
TOTAL	8.76

Combustion Turbine — Natural Gas

Pollutant	Uncontrolled Emission Factor (lb/MMBtu)[2,3]	Normal CTG Maximum Heat Input (Mbtu/h)[4]	CTG using Power Augmentation Maximum Heat Input (Mbtu/h)[4]	Facility PTE (tpy)
1, 3-Butadiene	4.30E-07	1903.1	1903.1	0.0072
2-Methylnaphthalene				
3-Methylchloranthrene				
7,12-Dimethylbenz(a)anthracene				
Acenaphthene				
Acenaphthylene				
Acetaldehyde	4.00E-05	1903.1	1903.1	0.6668
Acrolein	6.40E-06	1903.1	1903.1	0.1067
Anthracene				
Benz(a)anthracene				
Benzene	1.20E-05	1903.1	1903.1	0.2001
Benzo(a)pyrene				
Benzo(b)fluoranthene				
Benzo(g,h,i)perylene				
Benzo(k)fluoranthene				
Chrysene				
Dibenzo(a,h)anthracene				
Dichlorobenzene				
Ethylbenzene	3.20E-05	1903.1	1903.1	0.5335
Fluoranthene				
Fluorene				
Formaldehyde[5]	8.42E-05	1903.1	1903.1	1.4037
Hexane				
Indeno(1,2,3-cd)pyrene				
Naphthalene	1.30E-06	1903.1	1903.1	0.0217
PAH	2.20E-06	1903.1	1903.1	0.0367
Phenanathrene				
Propylene Oxide	2.90E-05	1903.1	1903.1	0.4835
Pyrene				
Toluene	1.30E-04	1903.1	1903.1	2.1673
Xylenes	6.40E-05	1903.1	1903.1	1.0670
			TOTAL	6.69

Combustion Turbine — Oil

Pollutant	Uncontrolled Emission Factor (lb/MMBtu)[2,3]	Maximum Heat Input (Mbtu/h)	Facility PTE (tpy)[4]
1, 3-Butadiene	1.60E-05	2067.6	0.0331
2-Methylnaphthalene			
3-Methylchloranthrene			
7,12-Dimethylbenz(a)anthracene			
Acenaphthene			
Acenaphthylene			
Acetaldehyde			
Acrolein			
Anthracene			
Benz(a)anthracene			
Benzene	5.50E-05	2067.6	0.1137
Benzo(a)pyrene			
Benzo(b)fluoranthene			
Benzo(g,h,i)perylene			
Benzo(k)fluoranthene			
Chrysene			
Dibenzo(a,h)anthracene			
Dichlorobenzene			
Ethylbenzene			
Fluoranthene			
Fluorene			
Formaldehyde[10]	1.90E-04	2067.6	0.3928
Hexane			
Indeno(1,2,3-cd)pyrene			
Naphthalene	3.50E-05	2067.6	0.0724
PAH	4.00E-05	2067.6	0.0827
Phenanathrene			
Propylene Oxide			
Pyrene			
Toluene			
Xylenes			
		TOTAL	0.69

Total from Combustion Turbines GAS/OIL

Pollutant	Facility PTE (tpy)
1, 3-Butadiene	0.0403
2-Methylnaphthalene	
3-Methylchloranthrene	
7,12-Dimethylbenz(a)anthracene	
Acenaphthene	
Acenaphthylene	
Acetaldehyde	0.6668
Acrolein	0.1067
Anthracene	
Benz(a)anthracene	
Benzene	0.3138
Benzo(a)pyrene	
Benzo(b)fluoranthene	
Benzo(g,h,i)perylene	
Benzo(k)fluoranthene	
Chrysene	
Dibenzo(a,h)anthracene	
Dichlorobenzene	
Ethylbenzene	0.5335
Fluoranthene	
Fluorene	
Formaldehyde	1.7966
Hexane	
Indeno(1,2,3-cd)pyrene	
Naphthalene	0.0940
PAH	0.1194
Phenanathrene	
Propylene Oxide	0.4835
Pyrene	
Toluene	2.1673
Xylenes	1.0670
TOTAL	7.39

Total from CTs with Duct Burners GAS/OIL

Pollutant	Facility PTE (tpy)
1, 3-Butadiene	4.03E-02
2-Methylnaphthalene	1.12E-04
3-Methylchloranthrene	8.37E-06
7,12-Dimethylbenz(a)anthracene	7.44E-05
Acenaphthene	8.37E-06
Acenaphthylene	8.37E-06
Acetaldehyde	8.67E-01
Acrolein	1.07E-01
Anthracene	1.12E-05
Benz(a)anthracene	8.37E-06
Benzene	3.24E-01
Benzo(a)pyrene	5.58E-06
Benzo(b)fluoranthene	8.37E-06
Benzo(g,h,i)perylene	5.58E-06
Benzo(k)fluoranthene	8.37E-06
Chrysene	8.37E-06
Dibenzo(a,h)anthracene	5.58E-06
Dichlorobenzene	5.58E-03
Ethylbenzene	5.33E-01
Fluoranthene	1.40E-05
Fluorene	1.30E-05
Formaldehyde	2.15E+00
Hexane	8.37E+00
Indeno(1,2,3-cd)pyrene	8.37E-06
Naphthalene	9.69E-02
PAH	1.19E-01
Phenanathrene	7.91E-05
Propylene Oxide	4.83E-01
Pyrene	2.33E-05
Toluene	2.18E+00
Xylenes	1.07E+00

Metallic Hazardous Air Pollutants[1]

Duct Burner — Natural Gas

Pollutant	Uncontrolled Emission Factor (lb/10⁶ scf)[3]	Maximum Heat Input (Mbtu/h)	Facility PTE (tpy)[3]
Arsenic	2.00E-04	541.7	8.24E-04
Beryllium	1.20E-05	541.7	4.95E-05
Cadmium	1.10E-03	541.7	4.53E-03
Chromium	1.40E-03	541.7	5.77E-03
Cobalt	8.40E-05	541.7	3.46E-04
Lead			
Manganese	3.80E-04	541.7	1.57E-03
Mercury	2.60E-04	541.7	1.07E-03
Nickel	2.10E-03	541.7	8.65E-03
Selenium	2.40E-05	541.7	9.89E-05
		TOTAL	2.29E-02

Total from Duct Burners

Pollutant	Facility PTE (tpy)
Arsenic	8.24E-04
Beryllium	4.95E-05
Cadmium	4.53E-03
Chromium	5.77E-03
Cobalt	3.46E-04
Lead	
Manganese	1.57E-03
Mercury	1.07E-03
Nickel	8.65E-03
Selenium	9.89E-05
TOTAL	2.29E-02
TOTAL	8.78

Combustion Turbine — Natural Gas

No Natural Gas, Metallic HAPs listed in AP-42 for combustion turbines.

TOTAL

Combustion Turbine — Oil

Pollutant	Uncontrolled Emission Factor (lb/MMBtu)[3]	Maximum Heat Input (Mbtu/h)	Facility PTE (tpy)[4]
Arsenic	1.10E-05	2067.6	0.0023
Beryllium	3.10E-07	2067.6	0.001
Cadmium	4.80E-06	2067.6	0.010
Chromium	1.10E-05	2067.6	0.023
Cobalt			
Lead	1.40E-05	2067.6	0.029
Manganese	7.90E-04	2067.6	1.633
Mercury	1.20E-06	2067.6	0.002
Nickel	4.60E-06	2067.6	0.010
Selenium	2.50E-05	2067.6	0.052
		TOTAL	1.78

Total from Combustion Turbines GAS/OIL

Pollutant	Facility PTE (tpy)
Arsenic	0.0227
Beryllium	0.0006
Cadmium	0.0099
Chromium	0.0227
Cobalt	
Lead	0.0289
Manganese	1.6334
Mercury	0.0025
Nickel	0.0095
Selenium	0.0517
TOTAL	1.78
TOTAL	9.17

Pollutant	Facility PTE (tpy)
Arsenic	2.36E-02
Beryllium	6.90E-04
Cadmium	1.45E-02
Chromium	2.85E-02
Cobalt	3.46E-04
Lead	2.89E-02
Manganese	1.63E+00
Mercury	3.55E-03
Nickel	1.62E-02
Selenium	5.18E-02
TOTAL	17.95

Notes

[1] Factors are derived for 2 units operating at high loads (>=80 percent load) only.
[2] The AP-42 emission factors were based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60 degrees F.
[3] The AP-42 emission factors were based on an average distillate oil heating value (HHV) of 139 MMBtu/10^3 gallons.
[4] Fuel oil operation per year based on 1000 hours. Natural gas operation based on 7760 hours of normal operation and 1000 hours of power augmentation.
[5] From AP-42 (7/98) Table 1.4-3 and 1.4-4 and listed as a HAP as defined by Section 112(b) of the Clean Air Act.
[6] From AP-42 (7/98) Table 3.1-3.
[7] From AP-42 (7/98) Table 3.1-4.
[8] From AP-42 (7/98) Table 3.1-5.
[9] Formaldehyde emission factor from AP-42 Ch.3 Emission Factor Query for Natural Gas.
[10] Formaldehyde emission factor from AP-42 Ch.3 Emission Factor Query for Fuel Oil.

Table 3
Fuel Flow Rates Per CTG/HRSG

Case	Ambient Temperature (°F)	Load (%)	Heat Input HHV (Btu/hr)	Fuel Rate Gas (ft^3/hr) Oil (gal/hr)
Natural Gas[a] (ft^3/hr)				
1	19	100	1.90E+09	1.94E+06
2	19	75	1.53E+09	1.56E+06
3	19	50	1.22E+09	1.25E+06
4	19	100	2.40E+09	2.45E+06
5	45	100	1.83E+09	1.87E+06
6	45	75	1.48E+09	1.51E+06
7	45	50	1.18E+09	1.21E+06
8	45	100	2.35E+09	2.40E+06
9	60	100	2.30E+09	2.34E+06
10	70	100	1.75E+09	1.79E+06
11	70	75	1.42E+09	1.45E+06
12	70	50	1.14E+09	1.16E+06
13	70	100	2.19E+09	2.24E+06
14	95	100	1.69E+09	1.73E+06
15	95	75	1.38E+09	1.41E+06
16	95	50	1.10E+09	1.12E+06
17	95	100	2.26E+09	2.30E+06
18	95	100	2.33E+09	2.37E+06
19	95	100	2.11E+09	2.15E+06
Distillate Fuel Oil[b] (gal/hr)				
20	19	100	2.07E+09	1.44E+04
21	19	75	1.66E+09	1.16E+04
22	19	50	1.30E+09	9.10E+03
23	45	100	1.99E+09	1.39E+04
24	70	100	1.91E+09	1.33E+04
25	95	100	1.84E+09	1.29E+04

[a]Based on a natural gas heat content of 23,325 Btu/lb (HHV) and density of 23.8 ft^3/lb.
[b]Based on a distillate oil heat content of 20,306 Btu/lb (HHV) and a density of 1 gal/7.05 lb.

COOLING TOWER EMISSION RATE ESTIMATES

Particulate matter (PM/PM_{10}) emissions from the induced draft mechanical cooling tower were estimated using procedures found in AP42, Section 13.4, Wet Cooling Towers.

A. Cooling Tower Data

Total Liquid Drift = 0.002% of recirculation water flow rate
Total Liquid Drift = 0.002 gal/100 gal recirculation water flow rate

Recirculation Water Flow Rate = 125,000 gal/min

Recirculation Water Total Dissolved Solids (TDS) = 3,704

B. PM/PM_{10} Emission Rate Calculations

PM/PM_{10} = (125,000 gal / min) x (0.002 gal / 100 gal H_2O) x (8.345 lb / gal H_2O) x (3,704 lb PM/PM_{10} / 10^6 lb water) x (60 min / hr)

PM/PM_{10} = 4.64 lb/hr

PM/PM_{10} = 20.32 ton/yr (8,760 hours/year operation)

Attachment O
Pollution Control Equipment Description

3.0 Best Available Control Technology

A summary of the best available control technology (BACT) analysis for the Project has been included below. Additionally, the detailed BACT for the Project has been included as Attachment 4.

The following is a summary of the BACT determination and associated emission rates for two GE PG7241(FA) combustion turbines operating with duct burners in combined cycle mode and one cooling tower to be installed for the project. The combustion turbines will fire natural gas and No. 2 fuel oil. The duct burners will fire only natural gas. Emissions for the BACT analysis are based on each CCCT/HRSG unit operating at three different operating conditions. These three conditions are 1) natural gas operation at full load with duct burner firing for 6,760 hours per year at and ambient temperature of 70°F, 2) natural gas firing with power augmentation for 1,000 hours per year at an ambient temperature of 70°F with the combustion turbine and duct burner firing at full load, 3) fuel oil firing of the combustion turbine-generator (CTG) unit at full load operation without duct firing for 1,000 hours per year at an ambient temperature of 70°F.

GE PG7241(FA) CCCT/HRSG Units:

Nitrogen oxides (NO_x) emissions -- BACT was determined to be the use of dry low NO_x burners with selective catalytic reduction (SCR) during natural gas firing and water injection with an SCR for fuel oil firing to achieve the following emission limits.
Burning natural gas at full load (with and without power augmentation) and duct firing, an emission limit of 3.5 ppmvd at 15 percent O_2.
Burning fuel oil at full load, an emission limit of 10 ppmvd at 15 percent O_2.

Carbon monoxide (CO) emissions -- BACT was determined to be good combustion controls to achieve a CO emission limit of 18.1 ppmvd at 15 percent O_2 (without power augmentation) and 26.3 ppmvd at 15 percent O_2 (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a CO emission limit of 14.3 ppmvd at 15 percent O_2 during fuel oil firing.

Particulate (PM/PM_{10}) emissions -- BACT was determined to be good combustion controls during natural gas and fuel oil firing.

Volatile Organic Compounds (VOC) emissions -- BACT was determined to be good combustion controls to achieve a VOC emission limit of 3.6 ppmvd at 15 percent O_2

(without power augmentation) and 6.3 ppmvd at 15 percent O_2 (with power augmentation) during natural gas firing. BACT was determined to be good combustion controls to achieve a VOC emission limit of 2.7 ppmvd at 15 percent O_2 during fuel oil firing.

Sulfur Dioxide (SO_2) emissions -- BACT was determined to be good combustion controls using natural gas and fuel oil with less than 0.05 percent sulfur.

Cooling Tower:

Particulate (PM/PM_{10}) emissions -- BACT is determined to be the use of drift eliminators with a control efficiency of 0.002 percent.

Attachment P
Shartup – Shutdown Procedures

May 16, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Robert G. Moore, Senior Vice President
Southern Company Services
One Energy Place
Pensacola, Fl 32520

Re: DEP File No. 0950137-002-AC, PSD-FL-313
Stanton Unit A Permit Revisions

Dear Mr. Moore:

The Department has reviewed your request to modify the PSD Permit relative to start-up emissions and CEMS span values. As a result of this review, the Department has concluded that a permit modification may be granted. Accordingly, this request is acceptable as indicated herein.

Permit PSD-FL-313 is hereby modified as follows:

26. Excess emissions resulting from startup, shutdown, fuel switching or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period ~~except during a "cold start-up" to combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 72 hours~~. During any 24-hour period in which an hour of start-up or shutdown occurs, the following alternative emission limits shall apply on the basis of a 24-hour rolling average:

    a) An alternative NO_X limit of 127 lb/hr shall apply if natural gas is the exclusively fired fuel

    b) An alternative NO_X limit of 370 lb/hr shall apply if any fuel oil is fired

    c) An alternative CO limit of 155 lb/hr firing either natural gas or fuel oil

    The 24-hour averages shall be based on all available data excluding calibration data. Operation below 50% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [BACT, Applicant Request and Rule 62-210.700, F.A.C.].

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the emissions of NO_X and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NO_X and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_X and CO established in this permit. Compliance with the emission limits for NO_X shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit

Appendix 'J'
2003 Commercial Operation Combined Cycle Units
Cold Start Approximated Heat Balance Information

Rev. F
2/21/2003

	CASES								
	Temp. Matching			Ramp up to full CT Load				Sliding Pressure	
	1	2	2A	3A	4	5	6	7	AU02
CT Load (mw)	17	17	17	17	33.9	84.7	168	168	171
% CT Load	10	10	10	10	20	50	100	100	100
ST Load (mw)	9.452	10.7	23.24	25.49	37.56	60.95	88.47	91.1	91.9
CT Exh. Gas Temp. (F)	790	900	900	946	1049.6	1196.6	1130.3	1130.3	1125.8
CT Exh. Gas Flow (MMlb/hr)	2.25	1.96	1.96	1.84	2.11	2.37	3.49	3.49	3.54
MS Temp (F)	751	841	848	905	930	1027	1043	1050	1050
MS Press. @ ST(psia)	565	565	565	565	565	565	565	592	598
CRH Press. @ ST(psia)	153.5	152.1	151.8	153.3	157	146	199	202	204
CRH Temp. @ ST (F)	652	738	709	746	743	760	765	758	757
HP Stm Attemp. Spray Flow (lb/hr)	0	0	0	0	25,091	41,417	0	7,257	4,402
% Spray (as % of total module flow)									
MS Flow, Total (lb/hr)	168,194	174,765	170,495	189,299	227,923	291,921	422,518	454,919	459,978
MS Flow to ST (lb/hr)	128,000	128,000	170,495	189,299	227,923	291,921	422,518	454,919	459,978
MS Flow to BYP (lb/hr)	40,194	46,765	0	0	0	0	0	0	0
HRH Stm Temp. (F)	753	821	819	898	910	980	1001	1050	1050
HRH Stm Press. @ ST (psia)	146	144	144	144	144	123	164	162	163
RHTR Stm Attemp. Spray Flow (lb/hr)	0	17,036	16,841	0	30,972	61,248	48,419	3,327	1,074
% Spray (as % of total module flow)									
HRH Stm Flow, Total (lb/hr)	205,179	222,018	217,692	215,061	290,334	389,509	514,991	501,489	504,982
HRH Stm Flow to ST (lb/hr)	127,000	127,000	217,692	215,061	290,334	389,509	514,991	501,489	504,982
HRH Stm Flow to BYP (lb/hr)	78,179	95,017	0	0	0	0	0	0	0

NOTES
Case 1- First load steam turbine to minimum load.

Case 2-CT at 10%, at beginning of "SOAK" period (control steam temp. to 850F/820F), bypasses open, some RH spray required.

Case 2A-CT at 10%, at end of "SOAK" period (control steam temp. to 850F/820F, bypasses just closed, some RH spray required.

Case 3A- CT at 10% Load- No bypasses, just out of CT temp. match, No sprays.

Case 4- CT at 20% Load- No bypasses, out of CT temp. match, spray to 930F/910F to match Alstom temperature requirements.

Case 5-Assumes IP turbine Intercept valve is in sliding pressure. Alstom has a standard minimum of 145 PSIA (130 PSIG) to maintain Gland Seal Steam supply header pressure.

Case 6- 100% CT Load, 1026F/980F Spray Main Steam and HRH to Alstom temperature limits. (Earliest you can get to full CT load).

Case 7- 100 CT Load, 1050F/1050F No Evaporative Cooling

Case AU02- 100 CT Load, 1050F/1050F with Evaporative Cooling

Attachment Q
Alternative Responsible Official Certification

Department of Environmental Protection

Division of Air Resource Management

RESPONSIBLE OFFICIAL NOTIFICATION FORM

Note: A responsible official is not necessarily a designated representative under the Acid Rain Program. To become a designated representative, submit a certificate of representation to the U.S. Environmental Protection Agency (EPA) in accordance with 40 CFR Part 72.24.

Identification of Facility

1. Facility Owner/Company Name: Orlando Utilities Commission	
2. Site Name: Curtis H. Stanton Energy Center	3. County: Orange
4. Title V Air Operation Permit/Project No. *(leave blank for initial Title V applications)*: **0950137-001 AV**	

Notification Type *(Check one or more)*

- ☐ **INITIAL**: Notification of responsible officials for an initial Title V application.
- ☐ **RENEWAL**: Notification of responsible officials for a renewal Title V application.
- **X** **CHANGE**: Notification of change in responsible official(s).
  Effective date of change in responsible official(s) November 2, 2003

Primary Responsible Official

1. Name and Position Title of Responsible Official: Frederick F. Haddad, Jr.
   Vice President, Power Resources
2. Responsible Official Mailing Address: P.O. Box 3193, Orlando, Florida 32801
   Organization/Firm: Orlando Utilities Commission
   Street Address: 500 South Orange Ave.
   City: Orlando State: Florida Zip Code: 32802
3. Responsible Official Telephone Numbers:
   Telephone: (407) 244-8732 Fax: (407) 275-4120
4. 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.

[X] 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.

5. Responsible Official Statement:

I, the undersigned, am a responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this notification. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this notification are true, accurate and complete. Further, I certify that I have authority over the decisions of all other responsible officials, if any, for purposes of Title V permitting.

Signature Date 10/10/03

Additional Responsible Official

1. Name and Position Title of Responsible Official: Ronald H. Walston
   Plant Manager

2. Responsible Official Mailing Address: P. O. Box 781295
   Organization/Firm: Southern Company
   Street Address: 5100 South Alafaya Trail
   City: Orlando State: Florida Zip Code: 32878

3. Responsible Official Telephone Numbers:
   Telephone: (321) 235- 2521 Fax: (321) 235-2595

4. Responsible Official Qualification *(Check one or more of the following options, as applicable)*:

[X] 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.

Additional Responsible Official

1. Name and Position Title of Responsible Official:

2. Responsible Official Mailing Address:
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

3. Responsible Official Telephone Numbers:
   Telephone: ( ) - Fax: ( ) -

4. 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.

Attachment R
Compliance Assurance Monitoring (CAM)

STANTON COMBINED CYCLE UNIT A
COMPLIANCE ASSURANCE MONITORING PLAN

Combined Cycle Units 025 and 026
NO_x Emissions Controlled by SCR

	INDICATOR NO. 1	INDICATOR NO. 2
I. Indicator	NO_x concentration	
Measurement Approach	NO_x concentrations are measured continuously using a NO_x/CO_2 CEMS installed and operated in accordance with 40 CFR Part 75.	
II. Indicator Range	An excursion is defined as a NO_x concentration above 3.5 ppmv @ 15% O_2 on a 3-hour block average basis when firing natural gas and above 10.0 ppmv @ 15% O_2 on a 3-hour block average basis when firing distillate fuel oil.	
III. Performance Criteria A. Data Representativeness	The NOx/CO2 CEMS inlet gas sample is obtained from ports located in the HRSG stack for each unit. The location of these sample ports and the sample gas system is in accordance with 40 CFR Part 75 requirements.	
B. Verification of Operational Status	NOx/CO2 EMS have been certified per 40 CFR Part 75 requirements.	
C. Quality Assurance and Control Practices and Criteria	Per 40 CFR Part 75 requirements	
D.1. Monitoring Frequency	Continuous	
D.2. Data Collection Procedures	Computerized data acquisition and handling system (DAHS).	
D.3. Averaging Period	3-Hour block	

Attachment S
Stanton A PSD Construction Permit

EN6 10-5-2
Stanton A

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

May 16, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Robert G. Moore, Senior Vice President
Southern Company Services
One Energy Place
Pensacola, Fl 32520

Re: DEP File No. 0950137-002-AC, PSD-FL-313
Stanton Unit A Permit Revisions

Dear Mr. Moore:

The Department has reviewed your request to modify the PSD Permit relative to start-up emissions and CEMS span values. As a result of this review, the Department has concluded that a permit modification may be granted. Accordingly, this request is acceptable as indicated herein.

Permit PSD-FL-313 is hereby modified as follows:

26. Excess emissions resulting from startup, shutdown, fuel switching or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period ~~except during a "cold start-up" to combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 72 hours.~~ During any 24-hour period in which an hour of start-up or shutdown occurs, the following alternative emission limits shall apply on the basis of a 24-hour rolling average:

    a) An alternative NO_X limit of 127 lb/hr shall apply if natural gas is the exclusively fired fuel

    b) An alternative NO_X limit of 370 lb/hr shall apply if any fuel oil is fired

    c) An alternative CO limit of 155 lb/hr firing either natural gas or fuel oil

    The 24-hour averages shall be based on all available data excluding calibration data. Operation below 50% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [BACT, Applicant Request and Rule 62-210.700, F.A.C.].

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the emissions of NO_X and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NO_X and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_X and CO established in this permit. Compliance with the emission limits for NO_X shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit

combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. The permittee may use the inlet SCR NO_X monitor as a backup analyzer in determining excess emissions during startup. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

The NO_X monitor shall be certified and operated in accordance with the following requirements. The NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 3-hour block. However, in the event that the permittee maintains 95% or greater availability of the continuous emission monitoring systems used for determining NO_X emissions compliance for the previous quarter, then compliance with the emission limits for NO_X shall be based on 3 valid consecutive hours of data for a 3-hour block average. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall ~~not be greater than~~ be between or inclusive of the values of 10 and 20 ppm, and the span for the upper range shall ~~not be greater than 30~~ be between or inclusive of the values of 200 and 250 ppm, as corrected to 15% O_2. The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to the Department's Central District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall ~~not be greater than~~ be between or inclusive of the values of 20 and 30 ppm, and the span for the upper range shall ~~not be greater than 100~~ be between or inclusive of the values of 500 and 1000 ppm, as corrected to 15% O_2. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

NO_X, CO and CO_2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X and CO emissions data recorded during ~~these episodes~~ malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit. ~~Periods of data excluded for startup shall not exceed two hours in any block 24-hour period except for "cold startup." A cold startup is defined as a startup following a complete shutdown lasting a minimum of 72 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block period. Periods of data excluded for malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all startup,~~

~~shutdown or malfunction episodes shall not exceed four hours in any 24-hour block period. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.~~

Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported to the Department's Central District office semi-annually, and shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur. Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. [Rules 62-4.070(3) and 62-212.400., F.A.C., and BACT]

[Note: Compliance with these requirements will ensure compliance with the other CEM system requirements of this permit to comply with Subpart GG requirements, as well as the applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.7(a)(5) and 40 CFR 60.13, and with 40 CFR Part 51, Appendix P, 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60, Appendix F, Quality Assurance Procedures].

No other changes to the permit are authorized by this action.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. This permit modification is issued pursuant to Chapter 403, Florida Statutes. Any party to this order (permit modification) has the right to seek judicial review of it under Section 120.68, F.S., by the filing of a Notice of Appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the Clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within (thirty) days after this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

Sincerely,

Howard L. Rhodes, Director
Division of Air Resources
Management

Mr. Robert G. Moore
May 13, 2003

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final PSD Permit Modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/20/03 to the person(s) listed:

Mr. Robert G. Moore, Southern Company *
Mr. Glenn D. Waters, Gulf Power
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Len Kozlov, CD
Mr. Buck Oven, DEP
Ms. Marie Driscoll, Orange County EPD

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson (Clerk) May 20, 2003 (Date)

Rec'd 9/28/2001 RS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. Robert G. Moore, VP Gulf Power Company
OUC/KUA/FMPA/Southern Company – Florida, LLC
One Energy Place
Pensacola, FL 32520-0328

DEP File 0950137-002-AC (PSD-313)
Curtis H. Stanton Energy Center
Orange County

Enclosed is the Final Permit Number PSD-FL-313. This permit authorizes the applicants to construct a natural-gas fired combined cycle unit known as Stanton Combined Cycle Unit A at the existing Curtis H. Stanton Energy Center in Orange County. This permit is issued pursuant to Chapter 403, Florida Statutes and 40CFR52.21.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

In addition to the appeal process described above, federal appeals procedures concerning this PSD permit are outlined in 40CFR 124.19, which is attached. Any person who filed comments on the draft permit may petition the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments on the draft permit may petition for administrative review only to the extent of the changes from the draft to the final permit decision.

The petition must be filed with the Environmental Appeals Board within 30 days of issuance of this Notice. Petitions may be addressed to the Environmental Appeals Board, MC 1103B, U.S. Environmental Protection Agency, 401 M Street, Washington, D.C. 20460. Further details are available at www.epa.gov/eab.

Executed in Tallahassee, Florida.

C.H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail* and copies were mailed by U.S. Mail before the close of business on 9/26/01 to the person(s) listed:

Robert G. Moore, Gulf Power *
Chair of County Commission, Orange County *
James O. Vick, Gulf Power
Rodney I. Unruh, P.E. (Black & Veatch)
Gregg Worley, EPA
John Bunyak, NPS
Len Kozlov, DEP-Central District
Marie Driscoll, Orange County EPD
Tasha O. Buford, E., Attorney
Mr. Hamilton S. Oven, DEP-Siting

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson 9/26/01
(Clerk) (Date)

FINAL DETERMINATION

OUC/KUA/FMPA/Southern Company – Florida, LLC
Stanton Energy Center Combined Cycle Unit A
DEP File No. PA 81-14SA2, PSD-FL-313

The Department distributed a public notice package on May 17, 2001 to allow the applicant to make a combined cycle unit addition at the existing Curtis H. Stanton Energy Center located in Orlando, Orange County. The Public Notice of Intent to Issue was published in the Orlando Sentinel on May 27, 2001.

COMMENTS/CHANGES

Comments were received from the EPA dated May 17 and June 18, 2001.

Comments were received from the Fish & Wildlife Service dated February 9, 2001.

Comments on the draft permit were received from the applicant by letter dated April 25, 2001.

Comments were reviewed and incorporated into the Draft Conditions of Certification.

Pursuant to notice, the Division of Administrative Hearings, by its duly designated Administrative Law Judge, C. A. Stampelos, conducted a formal site certification hearing (Case No. 01-0416EPP) in this proceeding on June 26, 2001 in Orange County, Florida. On July 23, 2001, it was recommended that the Siting Board grant full and final certification to the Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency, and Southern-Florida, LLC, under Section 403, Part II, Florida Statutes, for the location, construction, and operation of Stanton Unit A and its associated facilities, as described in the Supplemental Site Certification Application and the evidence presented at the certification hearing.

On September 11, 2001 the Siting Board concurred with the Administrative Law Judge's recommendation and authorized issuance of related permits via its Final Order.

CONCLUSION

The final action of the Department is to issue the permit consistent with changes described above.

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

PERMITTEE:

OUC/KUA/FMPA/Southern Company – Florida, LLC
One Energy Place
Pensacola, FL 32520-0328

File No.	PSD-FL-313 (PA81-14SA2)
FID No.	0950137
SIC No.	4911
Expires:	December 31, 2004

Authorized Representative:

Mr. Robert G. Moore, VP of Power Generation and Transmission, Gulf Power Company

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of a nominal 640 megawatt (MW) Combined Cycle unit consisting of: two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system; two supplementally fired heat recovery steam generators (HRSGs), each with a 160 ft. stack; one steam turbine-electrical generator rated at approximately 300 MW; one fresh water cooling tower; one distillate fuel storage tank and ancillary equipment. The combined cycle unit will achieve approximately 700 megawatts during extreme winter peaking conditions. The unit is to be installed at the existing OUC Stanton Energy Center, located at 5100 South Alafaya Trail, Orlando, Orange County. UTM coordinates are: Zone 17; 483.61 km E, 3151.1 km N.

STATEMENT OF BASIS:

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR52.21. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection.

The attached Appendices are made a part of this permit:

Appendix GC	Construction Permit General Conditions
Appendix GG	Subpart GG, Standards of Performance for Stationary Gas Turbines
Appendix XS	Semi-Annual Continuous Emission Monitor Systems Report

Howard L. Rhodes, Director
Division of Air Resources Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

OUC Stanton Energy Center consists of two fossil fuel fired steam electric generating stations, E.U. ID No. -001 (Unit No. 1) and -002 (Unit No. 2); also, there are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash. This project includes: two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system; two supplementally fired heat recovery steam generators (HRSGs), each with a 160 ft. stack; one steam turbine-electrical generator rated at approximately 300 MW; one fresh water cooling tower; one distillate fuel storage tank and ancillary equipment.

The turbines will be equipped with Dry Low NO_X combustors as well as an SCR in order to control NO_X emissions to 3.5 ppmvd at 15% O_2 while firing natural gas. During fuel oil firing, emissions will be held to 10 ppmvd at 15% O_2 using SCR plus water injection. Pipeline quality natural gas, 0.05% sulfur oil and good combustion practices will be employed to control all pollutants.

EMISSIONS UNITS

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
025	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
026	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
027	Water Cooling	One 10 cell Mechanical Draft Cooling Tower
028	Fuel Storage	One 1,680,000 Gallon Distillate Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry (fossil fuel-fired steam electric plant) included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of SO_2 and NO_X, 25/15 TPY of PM/PM_{10}, 100 TPY of CO and 40 TPY of VOC's. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This project is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting. [Chapter 403.503 (12), F.S., Definitions]

SECTION I - FACILITY INFORMATION

Based on the Title V permit, this facility is not currently a major source of hazardous air pollutants (HAPs). This facility is subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

PERMIT SCHEDULE

- 09/21/01 PSD Permit Issued
- 09/11/01 Site Certification Issued
- 05/27/01 Notice of Intent to Issue PSD Permit published in Orlando Sentinel
- 05/17/01 Distributed Intent to Issue Permit
- 05/01/01 Application Complete
- 01/22/01 Received PSD Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but are not incorporated into this permit. These documents are on file with the Department.

- Application received on January 22, 2001.
- Letter from Fish & Wildlife Service dated February 9, 2001.
- Additional information received from applicant on May 1, 2001.
- Department's Intent to Issue and Public Notice Package dated May 17, 2001.
- Department's Draft Permit and Draft BACT determination dated May 17, 2001.
- Letters from EPA Region IV dated May 17 and June 18, 2001.
- Site Certification for the Stanton A Combined Cycle addition dated September 11, 2001.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767 and phone number 407/894-7555.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21 (j) and 40 CFR 51.166(j), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 52.21(j), 40 CFR 51.166(j) and Rule 62-4.070 F.A.C.]
8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit. In conjunction with extension of the 18-month periods to commence or continue construction, or extension of the December 31, 2004 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.080, F.A.C.]

9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]

10. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Central District Office. [Chapter 62-213, F.A.C.]

11. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

12. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Central District Office by March 1st of each year.

13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Central District Office.

APPLICABLE STANDARDS AND REGULATIONS

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.

2. NSPS Requirements: Each combustion turbine (CT) shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. **Subpart A, General Provisions**, including: 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

   b. **Subpart GG, Standards of Performance for Stationary Gas Turbines;** see attached *Appendix GG.*

3. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

4. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

5. ARMS Emissions Units 025 and 026. Direct Power Generation, each consisting of a nominal 170 megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). Additionally, each Emissions Unit consists of a supplementally fired heat recovery steam generator equipped with a natural gas fired 542 MMBTU/hr duct burner (HHV) and combined with a nominal 300 MW steam electrical generators. These shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.

6. ARMS Emission Unit 027. Cooling Tower, an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because chromium-based chemical treatment is not used.

7. ARMS Emission Unit 028. Fuel Storage Tank, consisting of a 1,680,000 gallon distillate fuel storage tank. The storage tank is subject to 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984.

8. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District Office.

GENERAL OPERATION REQUIREMENTS

9. Fuels: Only pipeline natural gas or (up to) 1000 hours per year of 0.05% distillate fuel oil shall be fired in each CT emissions unit. Only natural gas shall be fired in each duct burner. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Combustion Turbine Capacity: The maximum heat input rates to each CT/HRSG shall not exceed 2,402 million Btu (HHV) per hour (MMBtu/hr) when firing natural gas with duct burner firing and power augmentation. The maximum heat input rates to each CT/HRSG shall not exceed 2,068 MMBtu/hr (HHV) when firing fuel oil. Manufacturer's curves corrected for ISO conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. {Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability} [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

11. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 533 MMBtu/hour (LHV) at any temperature or under any scenario. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

12. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

13. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Central District office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

14. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices of pollution control equipment shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

15. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

16. Maximum allowable hours of operation for each CT/HRSG Emissions Unit are 8760 hours per year while firing natural gas. Fuel oil firing is permitted for 1000 hours during any consecutive 12-month period in each CT. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

17. Simple Cycle Operation: The plant may not be operated without the use of the SCR system except during periods of startup and shutdown.

CONTROL TECHNOLOGY

18. Dry Low NO_X (DLN) combustors and water injection capability shall be installed on each stationary combustion turbine. The permittee shall install a selective catalytic reduction system to comply with the NO_X and ammonia limits listed in Specific Condition 21. Additionally, space shall be provided for the installation of oxidation catalysts. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

19. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 21 through 25. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

20. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions. A certification letter, following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002-gallons/100 gallons recirculation water flowrate.

EMISSION LIMITS AND STANDARDS

21. Nitrogen Oxides (NO_X) Emissions:

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on natural gas shall not exceed 3.5 ppmvd @15% O_2 on a 3-hr block average. This limit shall apply whether or not the unit is operating with duct burner on and/or in power augmentation mode. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- The emissions of NO_X in the stack exhaust gas, with the combustion turbine operating on fuel oil shall not exceed 10.0 ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition 30 for compliance procedures). [Applicant Request, Rule 62-4.070 and 62-204.800(7), F.A.C.]
- The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 5.0 ppmvd @15% O_2. The compliance procedures are described in Specific Conditions 29 and 45. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]

22. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on natural gas shall not exceed 17 ppmvd @15% O_2 on a 24-hr block average to be demonstrated by CEMS; and neither 14 ppmvd @15% O_2 with the CT operating on fuel oil on a 24-hr block average to be demonstrated by CEMS. These limits shall also be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing. Within 24 months of the date of completion of initial testing, the applicant shall either have installed oxidation catalyst in each CT/HRSG or forfeit its right to do so with the pre-determined (BACT) emission limits specified below. [BACT, Rule 62-212.400, F.A.C.]

- In the event that an oxidation catalyst is installed for any reason in either CT/HRSG pair within 24 months of the date of completion of initial testing, the limits for CO and VOC shall be 5 ppmvd

and 3 ppmvd (respectively) to be demonstrated by stack testing during power augmentation and duct burner firing (I, A). [BACT]

23. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall exceed neither 2.7 ppmvd @15% O_2 with the CT firing fuel oil and neither 6.3 ppmvd @15% O_2 with the CT firing natural gas (with maximum duct burner firing and operating in power augmentation mode); to be demonstrated by initial stack tests using EPA Method 18, 25 or 25A. [BACT, Rule 62-212.400, F.A.C.]

24. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 1.5 grains per 100 standard cubic foot) and up to 1000 hours per consecutive 12-month period of 0.05% sulfur fuel oil. Compliance with these fuel limits in conjunction with implementation of the attached Appendix GG will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner and the combustion turbine. Note: This will effectively limit the combined SO_2 emissions for EU-025 and EU-026 to approximately 134 tons per year. [BACT, 40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

25. PM/PM_{10} and Visible emissions (VE): VE emissions shall not exceed 10 percent opacity from the stack in use. [BACT, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during a "cold start-up" to combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 72 hours. Operation below 50% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [BACT, Rule 62-210.700, F.A.C.].

27. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

28. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions 41 through 45, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 21 through 25. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

29. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate for each fuel, but not later than 180 days of initial operation of

the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

30. Initial (I) performance tests shall be performed by the deadlines in Specific Condition 29. Initial tests shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or addition of oxidation catalyst (or change of combustors, if specifically requested by the DEP on a case-by-case basis). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.

    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement) shall be conducted a) while firing natural gas with maximum duct burner heat input as well as maximum power augmentation and b) while firing fuel oil at the maximum heat input; Initial test for compliance with 40CFR60 Subpart GG; Initial (only) NO_X compliance test for the duct burners (Subpart Da) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.
    - EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
    - Method CTM-027 for ammonia slip (I, A) to be completed simultaneously with NO_X compliance testing.

    The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O_2) at the measured lb/hr NO_X emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition 45.

31. Continuous compliance with the CO and NO_X emission limits: Continuous compliance with the CO and NO_X emission limits shall be demonstrated by the CEM system on the specified hour average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Specific Condition 41 further describes the CEM system requirements. Excess emissions periods shall be reported as required in Condition 28. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

32. Compliance with the SO_2 and PM/PM_{10} emission limits: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, the applicant is responsible for ensuring that the procedures outlined in attached Appendix GG are complied with.

33. Compliance with CO emission limit: An initial and annual test for CO shall be conducted at 100% capacity with the duct burners off. The NO_X and CO test results shall be the average of three valid one-hour runs. Annual RATA testing for the CO and NO_X CEMS shall be required pursuant to 40 CFR 75 and may substitute for the annual CO stack testing requirement.

34. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit will be employed as a surrogate and no annual testing is required [see Specific Condition 22 for exception].

35. Testing procedures: Unless otherwise specified, testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. inlet temperature). Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

36. Test Notification: The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance tests.

37. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, odors or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

38. Test Results: Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

39. Records: All measurements, records, and other data required to be maintained by the applicant shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

    - The applicant will be required to maintain records indicating the daily hours of operation of each CT/HRSG unit. These records shall specify which type of fuel is being combusted and the records shall be available for review at the site. Each calendar month, a compilation of the hours of operation for each CT/HRSG unit combusting fuel oil shall be made and totalized for the most recent consecutive 12-month period. Each AOR submitted by the applicant shall include a compilation of each consecutive 12-month period during the preceding calendar year.

40. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the emissions of NO_X and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NO_X and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of

this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_X and CO established in this permit. Compliance with the emission limits for NO_X shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

The NO_X monitor shall be certified and operated in accordance with the following requirements. The NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 3-hour block. However, in the event that the permittee maintains 95% or greater availability of the continuous emission monitoring systems used for determining NO_X emissions compliance for the previous quarter, then compliance with the emission limits for NO_X shall be based on 3 valid consecutive hours of data for a 3-hour block average. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to the Department's Central District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 20 ppm, and the span for the upper range shall not be greater than 100 ppm, as corrected to 15% O_2. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

NO_X, CO and CO_2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit. Periods of data excluded for startup shall not exceed two hours in any block 24-hour period except for "cold startup." A cold startup is defined as a startup following a complete shutdown lasting a minimum of 72 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block period. Periods of data excluded for malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all startup, shutdown or malfunction episodes shall not exceed four hours in any 24-hour block period. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.

Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported to the Department's Central District office semi-annually, and shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur. Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. [Rules 62-4.070(3) and 62-212.400., F.A.C., and BACT]

[Note: Compliance with these requirements will ensure compliance with the other CEM system requirements of this permit to comply with Subpart GG requirements, as well as the applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.7(a)(5) and 40 CFR 60.13, and with 40 CFR Part 51, Appendix P, 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60, Appendix F, Quality Assurance Procedures].

42. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Bureau of Ambient Monitoring & Mobile Sources (BAMMS) as well as the EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

43. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. No later than 90 days prior to operation, the permittee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

44. Subpart Da Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Da].

45. Selective Catalytic Reduction System (SCR) Compliance Procedures:

- An annual stack emission test for nitrogen oxides and ammonia from the CT/HRSG pair shall be simultaneously conducted while operating in the power augmentation mode with the duct burner on as defined in Specific Condition 21. The ammonia injection rate necessary to comply with the NO_X standard shall be established and reported during the each performance test.
- The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by manufacturer's guidelines and in accordance with this permit.
- The permittee shall install and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of the CT/HRSG set. It shall be maintained and calibrated according to the manufacturer's specifications.
- During the stack test, the permittee (at each tested load condition) shall determine and report the ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at the ammonia flow rate, which was established during the last stack test.
- In the event of a complaint or concern by an inspector, the permittee shall be capable of making an instantaneous measurement using inlet and outlet NO_X concentrations from the SCR system and ammonia flow supplied to the SCR system to determine ammonia slip. This determination shall not be used as a compliance method but only as an indicator to determine if a special compliance test is needed to demonstrate NO_X and ammonia slip requirements of the permit. The calculation procedure shall be provided with the CEM monitoring plan required by 40CFR Part 75. The following calculation represents one means by which the permittee may demonstrate compliance with this condition:

Ammonia slip @ 15%O_2 = (A-(BxC/1,000,000)) x (1,000,000/B) x D, where:

A= ammonia injection rate (lb/hr)/ 17 (lb/lb.mol)

B = dry gas exhaust flow rate (lb/hr) / 29 (lb/lb.mol)

C = change in measured NO_X (ppmv@15%O_2) across catalyst

D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

[Note: exhaust gas flow rate may be back calculated using heat input and F factor]

- The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device utilized to make the ammonia emission measurement and submitted with each annual compliance test.
- Upon specific request by the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements, in order to demonstrate that all NO_X and ammonia slip related permit limits can be complied with.

SECTION IV. APPENDIX GG

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

NSPS SUBPART GG REQUIREMENTS

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

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

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 in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (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).

Department requirement: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NO_X CEMS. The "Y" values are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit are more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel, which contains sulfur in excess of 0.8 percent by weight.

Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

Department requirement: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(1) Department requirement: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NO_X CEMS shall be used to demonstrate compliance with the NO_X limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

(2) [Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NO_X emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NO_X monitor is required to demonstrate compliance with the standards of this permit. Data from the NO_X monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NO_X) shall be computed for each run using the following equation:

$$NO_X = (NOxo)\,(Pr/Po)^{0.5}\, e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

where:

NO_X = emission rate of NO_X at 15 percent O2 and ISO standard ambient conditions, volume percent.

NOxo = observed NO_X concentration, ppm by volume.

Pr = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

Po = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H2O/g air.

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NO_X monitor continuously correct NO_X emissions concentrations to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the

minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: **The owner or operator is allowed to conduct initial performance tests at a single load because a NO_X monitor shall be used to demonstrate compliance with the BACT NO_X limits of this permit.**

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NO_X emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: **The owner or operator is allowed to make the initial compliance demonstration for NO_X emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NO_X monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.**

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: **The permit specifies sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.**

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

SECTION V. APPENDIX XS

SEMI-ANNUAL CONTINUOUS EMISSIONS MONITOR SYSTEMS REPORT

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: Nitrogen Oxides (NO_X) Carbon Monoxide (CO)

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer and Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period [a]: _____

Emission data summary [a]		CMS performance summary [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

[b] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes to CMS, process or controls during last 6 months.

I certify that the information contained in this report is true, accurate, and complete.

_____
Name

_____
Title

_____ _____
Signature *Date*

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages, which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law, which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

STANTON UNIT A COMBINED CYCLE PROJECT
OUC/KUA/FMPA/Southern Co.
PSD-FL-313 and PA81-14SA2
Orange County, Florida

BACKGROUND

The applicants, Orlando Utilities Commission (OUC), the Kissimmee Utility Authority (KUA), the Florida Municipal Power Agency (FMPA) and the Southern Company – Florida, LLC (SO), propose to build a 700 MW (estimated maximum gross capability) combined cycle power plant at the existing Curtis H. Stanton Energy Center. The location of the facility is 5100 South Alafaya Trail, Orlando, Orange County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). Therefore, the project is subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary units to be installed are two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system. The project includes two heat recovery steam generators (HRSGs), each with a 160 ft. stack and one steam turbine-electrical generator rated at approximately 300 MW. Duct burners will be installed in the HRSGs for supplemental firing and to achieve peak output. The project also includes one 10-cell linear mechanical draft cooling tower, and one diesel fuel storage tank (approximately 1,680,000 gallons). Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated June 30, 2001, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on January 22, 2001 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch. The proposal is summarized in the table below for each combustion turbine (MW loads are assumed to be at 50% or higher).

POLLUTANT	CONTROL TECHNOLOGY	BACT PROPOSAL
PM/PM_{10}, VE	Clean Fuels Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip
SO_2 / SAM	Clean Fuels	0.5 grains / 100 scf (gas) 0.05% Sulfur distillate oil – 1000 hours / year
CO	Pipeline Natural Gas Good Combustion	17 ppmvd (all operating modes) gas – 24 hr. avg. 14 ppmvd (all operating modes) oil – 24 hr. avg.
VOC	Pipeline Natural Gas Good Combustion	3.6 ppmvd / 2.7 ppmvd (gas / oil) 6.3 ppmvd during DB plus PA
NO_X	DLN & SCR	3.5 ppmvd @ 15% O_2 (gas) – 24 hr. avg. 10 ppmvd @ 15% O_2 (oil) – 24 hr. avg.
PM - cooling tower	High efficiency drift eliminators	0.002% drift loss

Based upon the applicant's submittal, the maximum annual emissions that the facility has the potential to emit (PTE) are as follows: 134.1 TPY SO_2, 17.6 TPY SAM, 127.6 TPY PM/PM_{10}, 314.5 TPY NO_X, 372.4 TPY CO and 105.8 TPY of VOC.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (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. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2. (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by the applicant is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the high efficiency units to be purchased. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

The duct burners required for supplementary gas-firing of the HRSGs are subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The 0.1 lb/MW-hr NO_X emission rate proposed by the applicant is well below the revised Subpart Da output-based limit of 1.6 lb/MW-hr promulgated on September 3, 1998. No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines or gas-fired duct burners.

The distillate fuel oil storage tank is subject to 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent BACT determinations by states for combined cycle stationary gas turbine projects. These are projects incorporating large prime movers capable of producing more than 150 MW excluding the steam cycle. Such units are typically categorized as F or G Class Frame units. The applicant's proposed BACT is included for reference.

TABLE 1

RECENT BACT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	Power Output Megawatts	NO_x Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Mobile Energy, AL	~250	~3.5 - NG (CT&DB) ~11 – FO (CT&DB)	DLN & SCR	178 MW GE 7FA CT 1/99 585 mmBtu Duct Burner
KUA Cane Island 3	250	3.5 - (CT&DB)	DLN/SCR	170 MW GE 7FA. 11/99 Ammonia slip = 5 ppmvd
Calpine BHEC	1080	3.5 – (CT& DB)	DLN/SCR	Ammonia slip = 5 ppm
Calpine Delta	880	2.5 – (CT & DB) 1 hour average (LAER)	DLN/CSR	3 GE 7FA's or 3 WH 501FD's; 10 ppm max ammonia slip
Calpine Bullhead City	545	3.0 – (CT&DB)	DLN/SCR	Nearly identical to Osprey; Replace SCR catalyst after 36 mo.
Calpine Osprey	545	3.5 – (CT& DB)	DLN/SCR	Ammonia slip = 9 ppm
Stanton A (proposed)	700	3.5 - NG (CT &DB & PA) 10 – FO	DLN/SCR	Ammonia slip = 5 ppm

DB = Duct Burner
NG = Natural Gas
FO = Fuel Oil
DLN = Dry Low NO_x Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection
CT = Comb. Turbine
DB = Duct Burner
PA = Pwr. Augmentation
PA = Power Augmentation
WH = Westinghouse
GE = General Electric

TABLE 2

RECENT BACT LIMITS FOR CARBON MONOXIDE, VOLATILE ORGANIC COMPOUNDS, PARTICULATE MATTER, AND VISIBILITY FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Mobile Energy, AL	~18 – NG (CT&DB) ~26 – FO (CT&DB)	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Calpine BHEC	10 – NG (CT only) 17 – NG (off-normal)	1.2 – NG (CT) 6.6 – NG (DB & PA)	10% Opacity 26.0 lb/hr (CT & DB)	Clean Fuels Good Combustion
Calpine Delta	10 – NG (CT & DB) 10 – NG (DB & PA) 3 hr avg. – No Ox. Cat.	2 - NG	0.25 gr.S/100 scf Nat. Gas	Clean Fuels Good Combustion
Calpine Bullhead City	10 – NG (CT & DB) 33.9 – NG (DB & PA) 3 hour rolling average	1.5 - NG	18.3 lb/hr (CT) 22.8 lb/hr (DB & PA)	Clean Fuels Good Combustion
Calpine Osprey	10 – NG (CT only) 17 – NG (off-normal)	2.3 – NG (CT) 4.6 – NG (DB & PA)	10% Opacity 24.1 lb/hr (CT & DB)	Clean Fuels Good Combustion
Stanton A (proposed)	14 –FO (CT only) 17 – NG (all gas modes)	2.7 – FO 6.3 – NG (DB & PA)	10% Opacity 11.7 / 17 lb/hr (NG / FO)	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, key information reviewed by the Department includes:

- Master Overview for Alabama Power Plant Barry Project received in 1998
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island 3
- Presentations by Black & Veatch and General Electric at EPA Region IV on March 4, 1999
- Letter from Black & Veatch to EPA Region IV dated March 10, 1999
- Letter from Black & Veatch to the Department and EPA Region IV dated March 24, 1999
- Texas Natural Resource Conservation Commission Draft Tier I BACT for August, 1999
- Texas Natural Resource Conservation Commission Website – www.tnrcc.state.tx.us
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas,

its use is minimized (1000 hours) for this project and control of NO_X emissions are proposed to be with SCR.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for the proposed turbines. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NO_X emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NO_X control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NO_X emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NO_X emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NO_X emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

Combustion Controls

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs between 50% to 100% of base load and provides the lowest NO_X emissions. Due to the intricate air and fuel staging necessary for dry low-NO_X combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%.

Figure A (below) is an example of an in-line duct burner arrangement. Since duct burners operate at lower temperature and pressure than the combustion turbine, the potential for emissions is generally lower. Although the duct burners maximum heat input is 533 MMBtu/hr, it is relatively low when compared with the turbine that can accommodate a heat input greater than 2000 MMBtu/hr. The duct burners will be of a Low NO_X design and will be used to compensate for loss of capacity at high ambient temperatures.

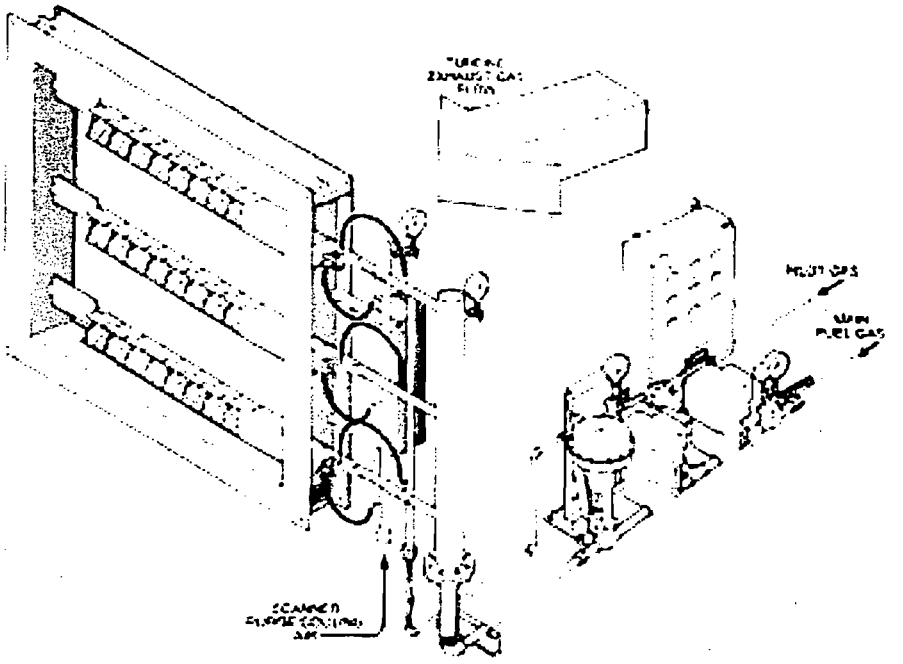


FIGURE A

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream within the HRSG. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming commonplace and have recently been specified for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review additionally concluded that the unit would be capable of combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10 ppmvd of NO_X. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan. These newer catalysts (versus the older alumina-based catalysts) are resistant to sulfur fouling at temperatures below 770°F (EPRI). In fact, Mitsubishi reports that as of 1998, SCR's were installed on 61 boilers which combust residual oil (40 of which are utility boilers) and another 70 industrial boilers, which fire diesel oil. Likewise, B & W reports satisfactory results with the installation of SCR to several large Taiwan Power Company utility boilers, which fire a wide range of coals, as well as heavy fuel oil with sulfur contents up to 2.0% and 50 ppm vanadium. Catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) currently employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12

ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3. New combined cycle combustion turbine projects in Florida are normally considered to be prime candidates for SCR.

Figure B is a photograph of FPC Hines Energy Complex. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. Figure C below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met.

Figure B

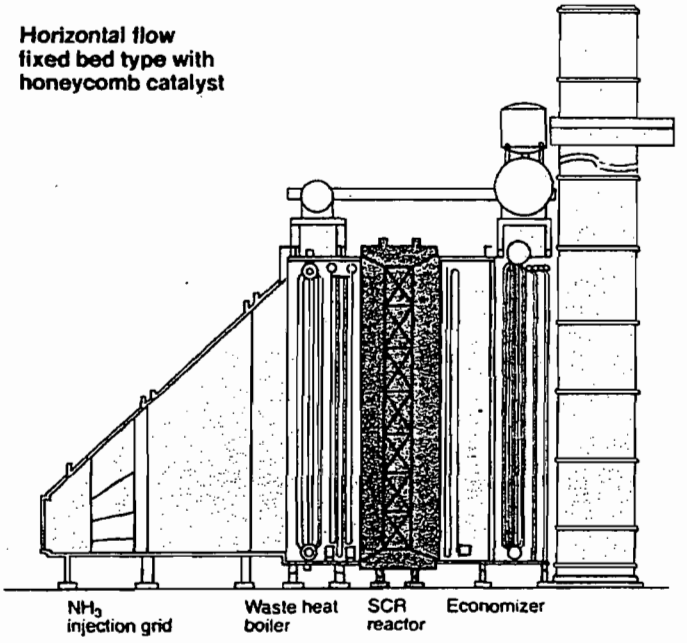


Figure C

Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur-bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits of 3.5 ppmvd NO_X are being routinely specified using SCR for F Class projects (with large in-line duct burners) in the Southeast and even lower limits in the southwest.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market an SCNR for NO_X control within the temperature ranges for which this project will operate (700 – 1400°F). However, the process also requires a low oxygen content in the exhaust stream in order to be effective. Given that a top-down review leads one to an SCR in this application, SNCR does not merit further consideration.

Emerging Technologies: SCONOx™ and XONON™

SCONOx™ is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[1] California regulators and industry sources have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx ™[2]. The overall project includes several more 250 MW blocks with SCR for control.[3] According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E Generating has been approved to install SCONOx™ on two F frame units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system.

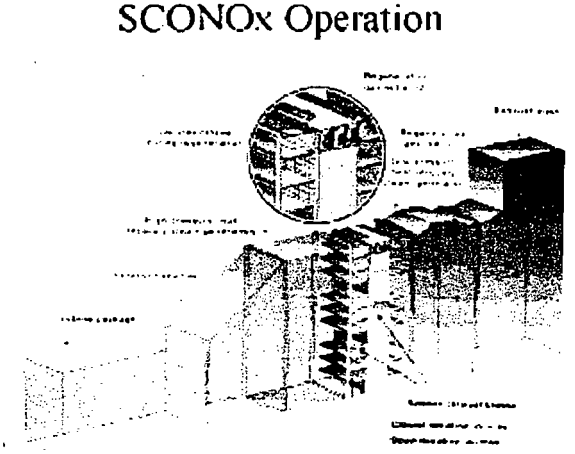


Figure D

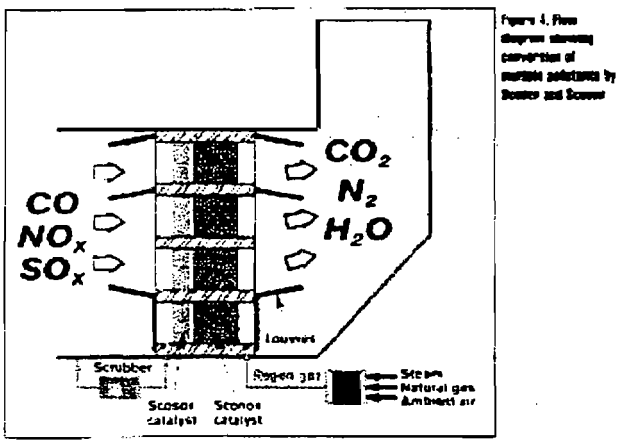


Figure E

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include (in addition to the reduction of NO_X) the elimination of ammonia and the control of VOC and CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently only due to cost considerations. The Department is interested in seeing this technology implemented in Florida and intends to continue to work with applicants seeking an opportunity to demonstrate ammonia-free emissions on a large unit. The Department estimates that the application of this control technology to the Stanton A Combined Cycle Unit results in cost-effectiveness of just less than $10,000 per ton of NO_X removed. Although there are specific items within the applicant's original analysis (which estimates a cost effectiveness of $10,200 per ton of NO_X and CO removed from each CT/HRSG) that the Department cannot support (e.g. lost power revenues, contingency factors above 3%, etc.) on balance the Department concurs with the conclusion that $SCONO_X$ is not likely cost-effective for this project.

Catalytica Energy Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the

combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as SCONOx™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

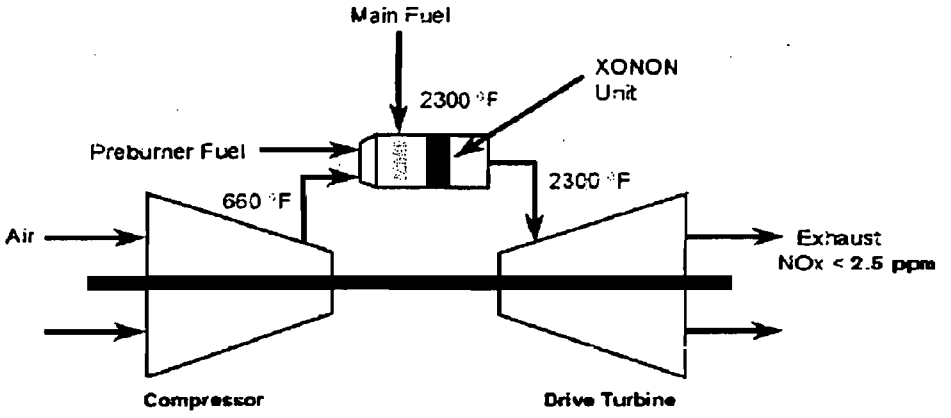
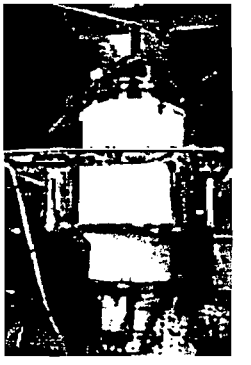


Figure F



XONON-2 installed with test instruments

Figure G

On February 8, 2001, Catalytica Energy Systems, Inc. announced that its XONON™ Cool Combustion system had successfully completed an evaluation process by the U.S. Environmental Protection Agency (EPA), which verified the ultra-low emissions performance of a XONON™-equipped gas turbine operating at Silicon Valley Power. The performance results gathered through the EPA's Environmental Technology Verification (ETV) Program provide high-quality, third party confirmation of XONON™ 's ability to deliver a near-zero emissions solution for gas turbine power production. The verification, which was conducted over a two-day period on a XONON™-equipped Kawasaki M1A-13A (1.4 MW) gas turbine operating at Silicon Valley Power, recorded nitrogen oxides (NO_X) emissions of less than 2.5 parts per million (ppm) and ultra-low emissions of carbon monoxide and unburned hydrocarbons.

The XONON™-equipped Kawasaki M1A-13A gas turbine has operated for over 7400 hours at Silicon Valley Power (SVP), a municipally owned utility, supplying near pollution-free power to the residents of the City of Santa Clara, California, with NO_X levels averaging under 2.5 ppm. Three XONON™-equipped Kawasaki M1A-13X turbines, a slightly modified commercial version of the M1A-13A, are expected to enter commercial service in late 2001 in Massachusetts at a healthcare facility of a U.S. Government agency.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to the commercialization of the XONON™ system for new and existing GE gas turbines. The agreement provides for the collaborative adaptation of XONON™ combustion technology to GE gas turbines for commercial sale. In December 1999, GE accepted the first order for XONON™ -equipped GE 7FA gas turbines as the preferred emission control system for Enron's proposed Pastoria Energy Facility. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. However, the technology cannot (at this time) be recommended for the attendant project.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) AND SO_2 CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas is an inherently clean fuel and contains no ash. Natural gas and very low sulfur fuel oil (0.05%) will be the only fuels fired at the Stanton Combined Cycle Unit and they are efficiently combusted in gas turbines making any conceivable add-on control technique for PM/PM_{10} or SO_2 either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} as well as SO_2 is a combination of good combustion practices, fuel quality, and filtration of inlet air.

The applicant has identified PM emissions over 20 TPY from the fresh-water mechanical cooling towers. Accordingly, drift eliminators shall be installed to reduce PM/PM_{10}. The drift eliminators shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate. No PM testing is required because the Department's Emission Monitoring Section has determined that there is no appropriate PM test method for these types of cooling towers.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst (excluding the SCONOx ™ process).

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Calpine Sutter in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review, which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. OUC/KUA/FMPA/SO propose to meet a limit of 14 ppmvd while firing fuel oil above 50% output. However, the applicant prefers to be permitted with higher values of 18.1 ppmvd and 27.9 ppmvd for the full output operating modes of duct burner firing, and duct burner firing with power augmentation, respectively. Duct burner firing is requested for the entire year and power augmentation is requested for up to 1000 hours per year.

The Department has reviewed actual data from similar facilities and has reasonable assurance that the General Electric PG7241FA units selected by the applicant will achieve values well below those proposed by the applicant (and guaranteed by GE), without requiring installation of an oxidation catalyst. However, should the applicant desire to obtain a sufficient operating margin above the BACT established limit identified below, the permit will authorize the installation of oxidation catalysts at an established limit of 5 ppmvd CO, providing that the applicant installs the catalyst within 24 months of commercial operation. Otherwise, the Department will require the use of a CEMS for compliance on a 24-hour block average, with two limits depending upon actual operation. The limits will be:

a) 14 ppmvd based upon a 24-hour block average for all periods of fuel oil firing; otherwise, the limit is

b) 17 ppmvd for all operating modes, based upon a 24-hour block average, which is consistent with the recently issued determination made at Blue Heron Energy Center

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by the applicant for this project are 3.6 ppmvd for gas firing with duct burners, 2.7 ppmvd while firing oil and 6.3 ppmvd during operation with duct burners plus power augmentation. According to the applicant's submittals, VOC emissions less than 2 ppm will be achieved at 100% output and duct burners off. [5]

REVIEW OF HAZARDOUS AIR POLLUTANTS (HAPS) CONTROL TECHNOLOGIES

Based upon the application, this facility will not emit HAPS above the significance thresholds, which would require the application of MACT. The formaldehyde emission factors that have been proposed by the applicant are 8.42E-5 lb/MMBtu and 1.90E-4 lb/MMBtu for gas and oil respectively. These are appropriate emission factors based upon AP-42, since the factors originated from the largest frame (7) machine within the AP-42 database. These are shown as 7EA Machines and listed in the database as ID No's 18 and 19 respectively. Annual formaldehyde emissions will therefore be approximately 2 TPY with total HAP emissions less than 18 TPY. Accordingly, the application of a MACT Determination is not required.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Stanton A Combined Cycle project assuming full load. Values for NO_X and CO are corrected to 15% O_2. The emission limits (or their equivalents) as well as the applicable averaging times are itemized within the Specific Conditions of the permit.

POLLUTANT	CONTROL TECHNOLOGY	BACT
PM/PM_{10}, VE	Clean Fuels Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip
SO_2 / SAM	Clean Fuels	0.5 grains / 100 scf (gas) 0.05% Sulfur distillate oil for 1000 hrs / year
CO	Pipeline Natural Gas Good Combustion	17 ppmvd (all operating modes) gas – 24 hr. avg. 14 ppmvd (all operating modes) oil – 24 hr. avg. 5 ppmvd (CT & DB & PA) with ox. catalyst
VOC	Pipeline Natural Gas Good Combustion	3.6 ppmvd / 2.7 ppmvd (gas / oil) 6.3 ppmvd during DB plus PA 3 ppmvd (CT & DB & PA) with ox. catalyst
NO_X	DLN & SCR	3.5 ppmvd @ 15% O_2 (gas) – 3 hr. avg. 10 ppmvd @ 15% O_2 (oil) – 3 hr. avg.
PM - cooling tower	High efficiency drift eliminators	0.002% drift loss

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd. It has been achieved at a small combustion turbine installation using $SCONO_X$.
- EPA Region IV advised that the Department (in a draft BACT) did not present "any unusual site-specific conditions associated with the KUA Cane Island 3 project to indicate that the use of SCR to achieve 3.5 ppmvd would create greater problems than experienced elsewhere at other similar facilities."[6] The Fish & Wildlife Service had similar comments for Calpine Osprey Energy Center.[8]
- FDEP considers a 3-hour averaging time for NO_X compliance and a 5-ppmvd ammonia slip rate to be BACT, as can be seen in other recent BACT Determinations.
- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5 ppmvd).[7]
- VOC emissions of < 2 ppm from the combustion turbine by Good Combustion proposed by the applicant are acceptable values determined as BACT. However, values less than 1 ppm have already been achieved on the DLN 2.6 combustors (GE 7FA) units after tuning.
- The CO emission rate will be verified continuously with CEMS. With the duct burner on, emissions will be less than 19 ppmvd, which is within the range of recent Department BACT determinations for combustion turbines alone. However, values as high as 28 ppmvd will not be authorized, as requested by the applicant. The CO limit will be 17 ppmvd on a weighted daily (24-hour block) average, which incorporates a reasonable allowance for all daily off-normal operations. In order to accommodate the applicant's concerns over the stringency of the limit, the installation of an oxidation catalyst will be authorized, provided that it is installed in a timely fashion.
- For reference, the CO limit for the FPL Fort Myers project is 12 ppmvd. Limits for the Santa Rosa Energy Center are 9 ppmvd with the duct burner off and 24 ppmvd with the duct burner on. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
PM/Visible Emissions	Method 5 (initial test only) and Method 9 (annually)
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	CEMS plus annual method 10 during operation at capacity without use of duct burners and power augmentation
VOC and CO with Oxidation Catalyst	Annual Method 18, 25 or 25A and Method 10 with Duct Burners and Power Augmentation
NO_X 3-hr block average	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 or 7E

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable standard. These excess emissions periods shall be reported as required within the Specific Conditions of the Permit. A valid hourly emission rate shall be calculated for each hour in which at least two pollutant concentrations are obtained at least 15 minutes apart. The following emission levels represent excess emission *estimates* during startup periods:

STARTUP TYPE	TIME	ESTIMATED EMISSION MAXIMUM LEVELS BY POLLUTANT FOR EACH CT (TOTAL lbm)				
		NO_X	SO_2	PM_{10}	VOC	CO
Natural Gas - Cold	4 hours	160	0	48	80	500
Natural Gas - Hot / Warm	2 hours	80	0	24	40	250

STARTUP TYPE	TIME	ESTIMATED EMISSION MAXIMUM LEVELS BY POLLUTANT FOR EACH CT (TOTAL lbm)				
		NO_X	SO_2	PM_{10}	VOC	CO
Distillate Oil - Cold	4 hours	360	400	70	80	500
Distillate Oil - Hot / Warm	2 hours	180	200	35	40	250

The following emissions (TPY) are shown for informational purposes only. They represent a *conservative* estimate of annualized startup emissions, which are largely controllable through best operating practices. Since each startup requires many hours of preceding shutdown time where emissions are zero, there will likely be *no annual net emission increase* from the previously estimated TPY:

STARTUP TYPE	NO. REQUIRED	NO_X	SO_2	PM_{10}	VOC	CO
Cold	48 (2 on oil)	4.1	0.4	1.2	1.9	12.0
Hot / Warm	240 (10 on oil)	10.1	1.0	0.7	4.8	30.0
Total	288 (12 on oil)	14.2	1.4	1.9	6.7	42.0

Excess emissions may occur under the following startup scenarios, subject to Rule 62-210.700, F.A.C. However, excess emissions resulting from startup, shutdown, or malfunction shall *only* be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

Hot / Warm Start: Two hours following a HRSG shutdown less than 72 hours.

Cold Start: Four hours following a HRSG shutdown greater than or equal to 72 hours.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

9/25/01
Date:

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

9/25/01
Date:

REFERENCES

1. News Release. Goaline Environmental. Genetics Institute Buys SCONOx Clean Air System. August 20, 1999.
2. "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.
3. Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.
4. Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.
5. Application for Air Permit, Attachment 2 Performance Data – GE Performance Data Natural Gas Firing Only.
6. Letter. Neeley, R. Douglas, EPA Region IV, to Fancy, C.H., FDEP. Draft PSD Permit – KUA Project. February 2, 1999.
7. Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.
8. Letter. Porter, Ellen to Linero, A.A., FDEP. Technical Review of Prevention of Significant Deterioration Permit Application For Osprey Energy Center. April 17, 2000.

Attachment T
Compliance Demonstration Reports

(Executive Summary of Results of PSD Certification Emissions Test Report dated July 2003)

Southern Company - Florida State PSD Certification Emissions Test Results

Permit Number: PSD – FL – 313

Plant Stanton
[Stanton A]
Units 25 & 26

July 2003

GULF POWER

A SOUTHERN COMPANY

I. *Executive Summary*

This report documents the permit mandated air emission testing performed at Stanton Energy Complex, Plant Stanton A located in Orlando, Florida. This combined cycle unit consists of two gas fired combustion turbines and a steam turbine. The effluent exhaust from the turbine and duct burner stages of the process pass through a selective catalytic reduction (SCR) emission control device, which greatly reduces the emission of oxides of nitrogen (NOx). Each of the gas turbines has its own stack from which the gases are released into the ambient air. For this reason each has its own continuous emissions monitoring system (CEMS). The following certification report is for the both units, designated as Units 25 and 26.

The continuous emission monitoring equipment, which consists of NOx, CO2, CO and O2 analyzers were installed in April, 2003. Boiler Tuning and initial CEMS start-up and calibrations were performed in May and June. On July 1st a pretest meeting was held with the Central Division of FDEP in order to summarize proposed testing procedures and schedules. Actual emission testing was conducted between July 22nd and August 5th, 2003. CEMS certification testing was completed on Unit 25 July 23rd and on Unit 26 August 20th. The testing was conducted according to the Environmental Protection Agency's (EPA) 40 CFR Part 60. This report documents the test reports and supporting data.

NOx and CO emissions were measured by use of a fully extractive or dry basis system. The NOx parts-per-million (ppm) dry basis measurement was corrected to 15% oxygen and standard conditions of temperature, pressure and humidity (International Organization for Standardization (ISO), conditions. In addition to NOx and CO, the emission tests included Volatile Organic Compounds (VOc), Ammonia, Stack Moisture, Visible Emissions (See CEMS Certification and Emissions Test Protocols in App. H.)

This test report will document that all emissions tests, required by the permit, and demonstrated compliance with the applicable permitted limits.

II. *Statement of Authenticity*

All field data collection and subsequent data reduction was done by the following personnel. We certify that the details and results presented in this report are authentic and accurate to the best of our knowledge.

Date: 9/2/2003 Signature: _____
John McPherson,
Environmental Specialist

Date: 9/10/2003 Signature: _____
G. Dwain Waters, QEP
Air Quality Programs Supervisor

III. *Summary of Test Results – Unit 25*

Unit	25	25	25	25	PERMIT EMISSION LIMIT
Date	7/22/03	7/23/03	8/05/03	7/24/03	
Mode	Turbine	Turbine/ Duct	Power Aug	Base Load Fuel Oil	
Turbine Generation (MW)	164	162	177	173	
Total NOx ppm vd @ 15% O2	2.476	2.508	3.123	7.874	**3.5 ppm (gas), 10 ppm (fuel oil)**
NOx lbs/mmBTU (NOx lbs/mmBTU w/ Duct Burners IN – OUT)*	.0091 (0.0001)*	.0092 (0.0001)*	NA	NA	**(.1 lbMMbtu)**
CO Emissions ppm vd @ 15% O2	.529	1.651	8.266	0.962	**17 ppm (gas), 14 ppm (fuel oil)**
CO Monitor RATA Results	.345	NA	NA	NA	**Abs. Value (RM-CEMS + CC) < 5 ppm**
VOC Emissions ppm vd @ 15% O2	.0473	.239	1.68	1.14	**2.7 ppm (fuel oil), 6.3 ppm (gas) CT+DB+PA**
Ammonia Slip	.201	.392	.927	2.90	**5 ppm**
Sulfur Content (grain/hcf) – gas (% by weight) - oil**	0.282	0.282	0.504	0.0407**	**<1.5 grains per 100 scf (.05% sulfur) - oil**
VE Test Results	0%	0%	0%	0%	**10%**

IV *Summary of Test Results – Unit 26*

Unit	26	26	26	26	PERMIT EMISSION LIMIT
Date	7/31/03	7/30/03	8/04/03	7/29/03	
Mode	Turbine	Turbine/ Duct	Power Aug	Base Load Fuel Oil	
Turbine Generation (MW)	165	166	176	171	
Total NOx ppm vd @ 15% O2	3.110	3.178	2.730	8.644	**3.5 ppm (gas), 10 ppm (fuel oil)**
NOx lbs/mmBTU w/ Duct (NOx lbs/mmBtu Burners IN – OUT)*	.0115 (0.0002)*	.0117 (0.0002)*	NA	NA	**(.1 lbMMbtu)**
CO Emissions ppm vd @ 15% O2	0.530	1.578	6.666	1.019	**17 ppm (gas), 14 ppm (fuel oil)**
CO Monitor RATA Results	.474	NA	NA	NA	**Abs. Value (RM-CEMS + CC) < 5 ppm**
VOC Emissions ppm vd @ 15% O2	.494	.258	.838	.777	**2.7 ppm (fuel oil), 6.3 ppm (gas) CT+DB+PA**
Ammonia Slip	.143	.452	.939	2.90	**5 ppm**
Sulfur Content (grain/hcf) – gas (% by weight) - oil**	0.533	0.615	0.496	0.0440**	**<1.5 grains per 100 scf (.05% sulfur)**
VE Test Results	0%	0%	0%	0%	**10%**

V *Discussion of Reference Methods and Test Equipment*

The reference method testing equipment is housed in a mobile continuous emission monitoring system. This trailer utilizes dilution extractive technology to analyze the stack emission concentrations.

The trailer is equipped with two separate data collection systems. Each system is totally independent. Both systems contain the gas measuring instruments and data collection systems.

The CO_2 is measured using a Siemens Ultramat 6 Analyzer. This monitor is a selective nondispersive infrared radiation (NDIR) gas analyzer that operates on the infrared double-beam, alternating light principle. The full range for the instrument is 10%. The serial number for the CO_2 analyzer is N5-672.

A ThermoEnvironmental Model 42C Nitrogen Oxides Gas Analyzer determines the NO_x levels in the gas stream. This monitor operates on the principle of chemiluminescence. This analyzer has a converter that converts NO_2 to NO to enable it to accurately measure the NO_x in the sample stream. The full range for the instrument is 200 ppm. The serial number for the NO_x monitor is 42C-70201-365.

Any additional information regarding instrument operation or capabilities can be obtained from the manufacturer or from Gulf Power Company by request.

The in-stack dilution probe is an EPM Environmental Model 797, and is constructed of Inconel, with a 316L stainless steel extension. The probe length is 10 feet. The probe extracts and dilutes the sample from the duct by creating an internal vacuum with respect to the flue gas. The sample is drawn through a glass critical orifice and mixed with clean dilution air that is provided by the trailer. This mixture is then delivered to the trailer to be analyzed by each instrument. The dilution ratio for this system is can be varied by selection of the critical orifice.

In addition, the trailer is equipped with a fully extractive (dry basis) system for purposes of measuring NOx, CO and Oxygen. The NOx monitor is a ThermoEnvironmental Model 42 CHL (serial number 42CHL-72771-372), the CO monitor is a ThermoEnvironmental Model 48C (serial number 48C-73019-373) and the O2 monitor is a ServoMax Model 1400 (serial number 14200/3116).

The fully extractive system utilizes a 200 foot heated umbilical which is temperature controlled by a digital temperature controller module. The system is typically set to control to 250 deg Fahrenheit. The probe, as well, is heated. The heated sample is brought down to the trailer into a KWW digitally controlled cooler assembly which serves to condense the moisture from the sample prior to its introduction into the gas analyzers. This system is plumbed with a network of stainless steel shut-off valves for purposes of specific leak checking.

The sample system is controlled via personal computer using the Spectrum Systems Spectra Test Software to interface with a SpectraPak Ioplexer controller. This interface enables the tester to manually initiate calibration gases to the probe, blowback of the system, and start all data collection.

All calibration gases that are used in the certification process are Certified Protocol 1 Calibration Gases. All certificates are included in Appendix I.

In addition to the Gulf Power test trailer from which the NOx, CO and O2 measurements were made, Sanders Engineering and Analytical Services, Inc. was on site with an 20 foot test trailer in order to make measure volatile organic compounds (Voc), Ammonia (NH3) and Moisture. A more complete description of the Sanders test equipment is given in the Sanders Engineering Test Report in Appendix G.

These emission tests utilized reference methods from CFR 40, Part 60, including NOx measurement by Method 7E, CO measurement by Method 10, VE measurement by Method 9, VOc measurement by Method 25A, Moisture measurement by Method 4 and Ammonia measurement by Method CTM-027, (Specific Conditions 29 and 45 [BACT, Rules 62-212, 400 and 62-4-070, F.A.C]. The *CEMS Certification and Emission Test Protocols* document in Appendix H gives more detail on test methods and test conditions, but essentially all parameters were measured at all of the permitted conditions except for the 50% load conditions. During these tests only moisture was measured in order to generate a moisture/load curve.

In addition to the emission measurements, relative accuracy test audits (RATAs) were performed on the NOx and CO continuous emissions monitoring systems. These RATAs, along with cycle time/response time tests, calibration error drift tests and linearity tests were required for the CEMS certification by 40 CFR, Part 75. The results

of these RATAs are given in Appendix A, sections 5 and 10. Because of the extremely low emission measurements from these systems, relative accuracy errors can be magnified. For this reason, in addition to the standard allowable percent relative accuracy as a measure of pass/fail, both the NOx and CO regulations allow for "alternative" standards for passing. In 40 CFR Part 75, App. A, Section 3.3.2 , *"when the NOx emission rate is less than or equal to .200 lb/mmBtu, the difference between the mean value of the CEM and the reference method mean value shall not exceed +/- .020 lb/mmBtu..."*. In 40 CFR Part 60, App. B, Performance Specification 4A, Section 13.2, there are three alternative passing results including: *the difference between the mean value of the CEM and the reference method mean value plus the 2.5% confidence coefficient shall not exceed 5 ppmv.* Both the NOx and CO RATAs passed utilizing these alternative standards.

Stratification tests were performed as described in 40 CFR, Part 75, 6.5.6. The results of these stratification tests are given in Appendix G. All traverse point measurements resulted in values that were within 5 percent of the mean of all the traverse point measurements.

Gas analyzer interference tests and NOx converter efficiency tests were performed and these results are included in Appendix J, Reference Method Analyzer Performance Results.

Although not specified for the primary permit emission limits ISO correction data was collected, and the emission monitoring system is set up to provide the parameters needed to perform the ISO correction if needed.

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Tel 850.444.6111

GULF POWER
A SOUTHERN COMPANY

FEDEX

September 15, 2003

Mr. Garry D. Kuberski
Engineer
Florida Department of Environmental Protection
Air Resources Management
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767

Mr. Kuberski:

RE: Stanton Unit 25 & 26 (Combined Cycle)
DEP File 0950137-002-AC (PSD-313)
ORIS Code: 55821
PSD Compliance Test Report

Please find, enclosed, one copy of the Compliance Test Report, which includes the test results for oxides of nitrogen emissions, carbon monoxide emissions, visible emissions, volatile organic compounds emissions, ammonia emissions and the SO2 for Units 25 & 26 (combined-cycle units) located at the Orlando Utilities Commission Plant Stanton in Orlando, Florida. Please note that we are also in the process of creating an electronic version of this report which will also be submitted.

The test results, as reported by Gulf Power's Field Services and Sanders Engineering & Analytical Services are summarized in the attached tables. These results demonstrate compliance with the facility's permit limits, also provided in the table.

Also attached is the certification of compliance document from Southern Power's Authorized Representative.

If you have any questions concerning the certification testing or the report, please call me at (850) 444-6527.

Sincerely,

Dwain Waters, QEP

G. Dwain Waters, QEP
Air Quality Programs Supervisor

Attachments (3)

Cc/watt: Jim Vick, Gulf Power Company
Ronnie Walston, Southern Power
Denise Stalls, Orlando Utilities Commission
Robert A. Schaffeld, Southern Power

Cc/woatt: Heather Turner, Southern Power
Joe Miller, Southern Power
Mike Markey, Gulf Power Company
✓John McPherson, Gulf Power Company
Errin Pichard, FDEP - Tallahassee
Issac Santos, FDEP - Tallahassee
Cindy Mulkay, FDEP – Tallahassee

CERTIFICATION BY RESPONSIBLE OFFICIAL
STANTON A REPORT

"I, the undersigned, am the authorized representative or responsible official, as defined in Chapter 62-210.200, F.A.C., for the PSD source for which this report is being submitted. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made and data contained in this submission are true, accurate and complete."

Responsible Official Signature:

Robert G. Moore

Robert G. Moore
Senior Vice-President Southern Company Services
& Senior Production Officer Southern Power

9/8/03

Date:

One Energy Place
Pensacola, Florida 32520

Tel 850.444.6111

GULF POWER
A SOUTHERN COMPANY

Certified

April 2, 2003

Mr. Scott M. Sheplak, P.E.
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Installation Confirmation and Guarantee of Performance
Combined Cycle Cooling Tower Drift Eliminators – Stanton Units 25 & 26
Specific Condition 20, PSD-FL-313, PA 81-14SA2

Dear Mr. Sheplak:

The cooling tower and drift eliminators for the Stanton A permit have been installed. The drift eliminators utilized meet the requirements in Specific Condition 20 of the PSD permit.

If you should have any questions regarding this submittal, please feel free to give me a call at (850) 444-6573.

Sincerely,

Richard "Mike" Markey, P.G., Q.E.P.
Environmental Affairs

Enclosure – Cooling Tower Drift Letter – Marley Cooling Technologies

Cc: Ronnie Walston, Southern Power
Robert Schaffeld, Southern Power
Heather Turner, Southern Power
Brian Barham, Southern Company Services
Danny Herrin, Southern Company Services
Tuck Tucker, Gulf Power Company
Jim Vick, Gulf Power Company
G. Dwain Waters, Gulf Power Company
Denise Stalls, OUC
Lynn Haynes, EPA – Region IV
Leonard Kozlov, FDEP – Central District
John Turner, FDEP – Central District
Garry Kuberski, FDEP – Central District

Marley Cooling Technologies
7401 W 129 Street
Overland Park, KS 66213 USA
913 664 7434
Fax 913 664 7857
darin_baugher@marleyct.com

March 22, 2003

Southern Company Site Manager
Stanton Combined Cycle Project
P.O. BOX 781295
Orlando, FL 32878

Att: Mr. Ronnie Walston

RE: Stanton Energy Center Cooling Tower Drift

Marley offers the following statement regarding the drift rate:

"The Stanton cooling tower was installed with Marley's TU12C drift eliminators. The TU12 eliminator is the latest in drift elimination technology and is designed to allow a maximum drift rate of 0.0005%."

I trust this will satisfy the concerns the plant has. Please contact us if you have any questions.

Sincerely,

Darin Baugher
Manager, Sales Support
Field Erected Products

Attachment U
Compliance Report & Plan

STANTON A COMBINED CYCLE

COMPLIANCE REPORT & PLAN

1. Compliance Report and Plan

Attachment A to this Title V operation permit renewal application identifies the requirements that are applicable to the emission units that comprise this Title V source. Each emissions unit is in compliance, and will continue to comply, with the respective applicable requirements.

The emission units that comprise this Title V source will comply with future-effective applicable requirements on a timely basis.

2. Proposed Schedule for the Submission of Periodic Compliance Statements Throughout the Permit Term

Periodic compliance statements are proposed to be submitted on an annual basis within 60 days after the end of each calendar year pursuant to the requirements of FDEP Rule 62-213.440(3)(a)2.a, F.A.C.