PAYNE CREEK GENERATING STATION

TITLE V PERMIT APPLICATION

Prepared for:

Seminole Electric Cooperative, Inc.
In Partnership With Those We Serve

Tampa, Florida

Prepared by:

ECT
Environmental Consulting & Technology, Inc.

3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 010896-0100

November 2001

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

RECEIVED
DEC 05 2001
BUREAU OF AIR REGULATION

December 4, 2001

Mr. Scott M. Sheplak, P.E.
FDEP-Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Payne Creek Generating Station
Title V Permit Application

Project No.: 0490340-002-AV

Dear Mr. Sheplak:

Enclosed are four copies of the initial Title V application for Seminole Electric Cooperative, Inc.'s Payne Creek Generating Station. Pursuant to Rule 62-213.420(1)(a)2., Fla. Admin. Code, Seminole is submitting this application which is ninety days prior to the expiration of its construction permit on March 4, 2002. As we discussed, the performance test for this unit has not yet been completed. Once we have scheduled and completed this test the results will be forwarded to the Department as soon as they are available.

We appreciate your cooperation and assistance in processing this application. If you have any questions or need any additional information, please contact Mike Roddy or myself at (813)963-0994.

Sincerely,

M.P. Opalinski

Mike Opalinski
Director of Environmental Affairs
Title V Responsible Official

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INTRODUCTION

Seminole Electric Cooperative, Inc. (SECI), has recently constructed and placed in operation an electric generation facility located approximately 9 miles northwest of Wauchula in Hardee County, Florida. The Payne Creek Generating Station (PCGS) consists of two nominal 157.5 megawatts (MW) combined-cycle Siemens Westinghouse 501F(D) combustion turbines (CT-1 and CT-2), one 1.35 million gallon distillate fuel oil storage tank, two 5.0 million British thermal units per hour (mmBtu/hr) heat input natural gas-fired fuel gas heaters, one 275 brake horsepower (hp) fire water pump diesel engine, water treatment facilities, one 20,000-gallon aqueous ammonia storage tank, and ancillary support equipment.

The combined-cycle combustion turbines each include one unfired heat recovery steam generator (HRSG). The CTs only operate in combined-cycle mode (i.e., the HRSGs are not equipped with bypass stacks). Steam generated by the two HRSGs is sent to one common nominal 173 MW steam turbine. The facility utilizes pipeline natural gas as its primary fuel source with distillate fuel oil serving as a backup fuel.

In May 1994, an Air Construction Permit application was submitted to the Florida Department of Environmental Protection (FDEP) requesting approval to install and operate the PCGS (formerly referred to as Hardee Power Station Unit 3). In response to this application, FDEP issued Prevention of Significant Deterioration (PSD) Permit No. PSD-FL-214 on September 28, 1995. In response to a request from SECI, this permit was subsequently modified to include selective catalytic reduction (SCR) and oxidation catalyst control systems. Modified FDEP Permit No. PSD-FL-214A was issued on July 23, 1999, with an expiration date of March 4, 2002. The Florida Power Plant Siting Act (PPSA) Certification for the PCGS (PA-89-25SA) was also subsequently modified to include these project revisions.

The PCGS commenced commercial operations on September 13, 2001. Emissions performance testing, as required by Permit No. PSD-FL-214A, Specific Condition Section C, is planned to be conducted during December 2001.

Pursuant to Rule 62-213.420(1)(a)2., Florida Administrative Code (F.A.C.), an application for a Title V operation permit must be filed 90 days prior to construction permit expiration (i.e., by December 4, 2001) and no later than 180 days after commencing operation (i.e., by March 12, 2002). This permit application, using FDEP Form No. 62-210.900(1), *Application for Air Permit—Title V Source*, constitutes SECI's application for a Title V Operation Permit for the PCGS, pursuant to the requirements of Chapter 62-213, F.A.C.

Following this introduction, a completed *Application for Air Permit—Title V Source* (including all required supporting material) is provided in Appendix A. A copy of air construction Permit No. PSD-FL-214A and revisions to this permit are provided in Appendix B.

APPENDIX A

APPLICATION FOR AIR PERMIT
TITLE V SOURCE

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Seminole Electric Cooperative, Inc.**	
2. Site Name: **Payne Creek Generating Station**	
3. Facility Identification Number: **1050340**	[ ] Unknown
4. Facility Location: Street Address or Other Locator: **6697 County Road 663** City: **Bowling Green** County: **Hardee** Zip Code: **33834**	
5. Relocatable Facility? [ ] Yes [✔] No	6. Existing Permitted Facility? [✔] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Mike Roddy** **Senior Environmental Engineer**
2. Application Contact Mailing Address: Organization/Firm: **Seminole Electric Cooperative, Inc.** Street Address: **16313 North Dale Mabry Highway** City: **Tampa** State: **FL** Zip Code: **33688-2000**
3. Application Contact Telephone Numbers: Telephone: **(813) 963 – 0994** Fax: **(813) 264 – 7906**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number: **PSD-FL-214A / PA-89-25SA**

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

Current construction permit number: ______________________

Operation permit number to be revised: ______________________

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

Operation permit number to be revised/corrected: ______________________

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

Operation permit number to be revised: ______________________

Reason for revision: ______________________

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Michael P. Opalinski, Director of Environmental Affairs**
2.	Application Contact Mailing Address: Organization/Firm: **Seminole Electric Cooperative, Inc.** Street Address: **16313 North Dale Mabry Highway** City: **Tampa** State: **FL** Zip Code: **33688-2000**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(813) 963 – 0994** Fax: **(813) 264 – 7906**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [✔], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* M. P. Opalinski 12/04/01 Signature Date

* Attach letter of authorization if not currently on file.

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: **FL** Zip Code: **32606**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 332-0444** Fax: **(352) 332-6722**

4. Professional Engineer Statement:

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

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

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

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

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

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

Thomas W. Davis
Signature

11/30/01
Date

(seal)

* Attach any exception to certification statement.

Please see attached exception statement.

SEMINOLE ELECTRIC COOPERATIVE, INC
PAYNE CREEK GENERATING STATION

EXCEPTION TO PROFESSIONAL ENGINEER STATEMENT

Professional Engineer Certification Statement with respect to compliance with applicable requirements is based on the expected performance of the emission source process and pollution control equipment. An initial compliance test will be conducted during December 2001 to confirm this expected performance.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
001	CTG/HRSG Unit 1	N/A	N/A
002	CTG/HRSG Unit 2	N/A	N/A

Application Processing Fee

Check one: [ ] Attached - Amount: $ ________ [✔] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations:

Project consists of two nominal 157.5 MW Siemens Westinghouse 501F(D) combined cycle combustion turbine generators (CTGs), two unfired heat recovery steam generators (HRSGs), and one nominal 173 MW steam turbine. The primary fuel for the CTGs is pipeline quality natural gas with low-sulfur, distillate fuel oil serving as a backup fuel.

The CTGs are equipped with dry low-NO_x (DLN) combustors. The HRSGs are equipped with selective catalytic reduction (SCR) and oxidation catalyst control systems.

Ancillary facility emission sources include one 1.35 MM gal distillate fuel oil storage tank, two 5.0 MMBtu/hr heat input natural gas-fired fuel heaters, and one 275 BHP fire water pump diesel engine.

2. Projected or Actual Date of Commencement of Construction: **April 2000**

3. Projected Date of Completion of Construction: **Not Applicable**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **405.049**	North (km): **3,057.712**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **27° 38' 30"**		Longitude (DD/MM/SS): **81° 57' 45"**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Jim Pittman, Plant Manager**		
2. Facility Contact Mailing Address: Organization/Firm: **Seminole Electric Cooperative, Inc.** Street Address: **6697 County Road 663** City: **Bowling Green**	State: **FL**	Zip Code: **33834**
3. Facility Contact Telephone Numbers: Telephone: **(863) 375-2828**	Fax: **(863) 375-3100**	

Facility Regulatory Classifications

Check all that apply:

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

List of Applicable Regulations

See Attachment I.	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NOX	**A**	**N/A**	**N/A**	**N/A**	
SO2	**A**	**N/A**	**N/A**	**N/A**	
CO	**A**	**N/A**	**N/A**	**N/A**	
PM10	**A**	**N/A**	**N/A**	**N/A**	
PM	**A**	**N/A**	**N/A**	**N/A**	
SAM	**B**	**N/A**	**N/A**	**N/A**	
VOC	**B**	**N/A**	**N/A**	**N/A**	
PB	**B**	**N/A**	**N/A**	**N/A**	
H021	**B**	**N/A**	**N/A**	**N/A**	
H015	**B**	**N/A**	**N/A**	**N/A**	
HAPS	**A**	**N/A**	**N/A**	**N/A**	**Total HAPS**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Emission unit consists of one Siemens/Westinghouse (S/W) 501F(D) combined-cycle combustion turbine generator (CTG) having a nominal rating of 157.5 megawatts (MW). The primary fuel for CT1 is pipeline quality natural gas with low-sulfur, distillate fuel oil serving as a backup fuel.

4. Emissions Unit Identification Number: [ ] No ID
ID: **001 (CTG/HRSG1)** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**September 2001**	**49**	[✔]

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

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

   NO_x Controls

   Dry low-NO_x combustors (natural gas-firing)
   Water injection (distillate fuel-oil firing)
   Selective Catalytic Reduction (SCR)

   CO Controls

   Oxidation catalyst

2. Control Device or Method Code(s): **025 (dry low-NO_x), 028 (water injection), 065 (catalytic reduction), and 080 (oxidation catalyst)**

Emissions Unit Details

1. Package Unit:
   Manufacturer: **Siemens Westinghouse** Model Number: **501F(D)**
2. Generator Nameplate Rating: **157.5** MW **(nominal)**
3. Incinerator Information:
   Dwell Temperature: °F
   Dwell Time: seconds
   Incinerator Afterburner Temperature: °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	**1,962 (HHV)** mmBtu/hr			
2. Maximum Incineration Rate:	lb/hr		tons/day	
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input is higher heating value (HHV) at 100 percent load, 32°F, natural gas fuel operating conditions. Heat input will vary with load, fuel type, and ambient temperature.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment I.	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **CTG/HRSG1**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **N/A**
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**

5. Discharge Type Code: **V**	6. Stack Height: **175** feet	7. Exit Diameter: **18.0** feet
8. Exit Temperature: **198** °F	9. Actual Volumetric Flow Rate: **1,016,286** acfm	10. Water Vapor: %

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

13. Emission Point UTM Coordinates:		
Zone:	East (km):	North (km):

14. Emission Point Comment (limit to 200 characters): **Stack temperature and flow rate are at 100 percent load, 59°F, and natural gas-firing operating conditions. Stack temperature and flow rate will vary with load, fuel type, and ambient temperature.**

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

Segment Description and Rate: Segment 1 of 2

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

Combustion turbine fired with pipeline quality natural gas.

2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.86**	5. Maximum Annual Rate: **16,293.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**

10. Segment Comment (limit to 200 characters):

Fuel heat content (Field 9) represents higher heating value (HHV).

Segment Description and Rate: Segment 2 of 2

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

Combustion turbine fired with distillate fuel oil.

2. Source Classification Code (SCC): **20100101**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **13.41**	5. Maximum Annual Rate: **41,751.0**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **0.01**	9. Million Btu per SCC Unit: **147**

10. Segment Comment (limit to 200 characters):

Maximum annual rate (Field 5) is total for both CTG/HRSG Units 1 and 2.

Fuel heat content (Field 9) represents higher heating value (HHV).

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – NOX	**025**	**065**	**EL**
2 – CO	**080**		**EL**
3 – PM			**EL**
4 – PM10			**EL**
5 – SO2			**EL**
6 – VOC			**EL**
7 – SAM			**EL**
8 – H021 (Beryllium Compounds)			**EL**
9 – H015 (Arsenic Compounds)			**EL**

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control: **64 %**
3. Potential Emissions: **336** lb/hour **906** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **336 lb/hr** Reference: **FDEP Permit PSD-FL-214A**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Hourly potential emission rate based on FDEP Permit PSD-FL-214A, Specific Conditions, B.1., distillate fuel oil-firing case. Annual potential emission rate is total for both CTG/HRSG Units 1 and 2 at 59°F with 1,500 hr/yr oil-firing per unit.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **12 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **91 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for natural gas-firing for the one year period following startup per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **Unit is also subject to less stringent NO_X limits of 40 CFR Part 60, Subpart GG (NSPS).** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **68 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for natural gas-firing after the one year period following startup per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **Unit is also subject to less stringent NO_X limits of 40 CFR Part 60, Subpart GG (NSPS).** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **42 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **336 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for distillate fuel oil-firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **Unit is also subject to less stringent NO_X limits of 40 CFR Part 60, Subpart GG (NSPS).** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control: **80 %**
3. Potential Emissions: **91** lb/hour **618** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **91 lb/hr** Reference: **FDEP Permit PSD-FL-214A**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Hourly potential emission rate based on FDEP Permit PSD-FL-214A, Specific Conditions, B.1., distillate fuel oil-firing case. Annual potential emission rate is total for both CTG/HRSG Units 1 and 2 at 59°F with 1,500 hr/yr oil-firing per unit.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **71 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10 (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for natural gas-firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **25 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **91 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10 (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for distillate fuel oil -firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **67** lb/hour **147** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **67 lb/hr** Reference: **FDEP Permit PSD-FL-214A**	7. Emissions Method Code: **0**

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

Hourly potential emission rate based on FDEP Permit PSD-FL-214A, Specific Conditions, B.1., distillate fuel oil-firing case. Annual potential emission rate is total for both CTG/HRSG Units 1 and 2 at 59°F with 1,500 hr/yr oil-firing per unit.

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **7 lb/hr**	4. Equivalent Allowable Emissions: **7 lb/hr**

5. Method of Compliance (limit to 60 characters):
EPA Reference Method 5B (initial only)

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

Emission limits applicable for natural gas-firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.

FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **67 lb/hr**	4. Equivalent Allowable Emissions: **67 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 5B (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for distillate fuel oil -firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **67** lb/hour **147** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **67 lb/hr** Reference: **FDEP Permit PSD-FL-214A**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Hourly potential emission rate based on FDEP Permit PSD-FL-214A, Specific Conditions, B.1., distillate fuel oil-firing case. Annual potential emission rate is total for both CTG/HRSG Units 1 and 2 at 59°F with 1,500 hr/yr oil-firing per unit.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **7 lb/hr**	4. Equivalent Allowable Emissions: **7 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 5B (initial only)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for natural gas-firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **67 lb/hr**	4. Equivalent Allowable Emissions: **67 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 5B (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for distillate fuel oil -firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **101** lb/hour **182** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **101 lb/hr** Reference: **FDEP Permit PSD-FL-214A**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Hourly potential emission rate based on FDEP Permit PSD-FL-214A, Specific Conditions, B.1., distillate fuel oil-firing case. Annual potential emission rate is total for both CTG/HRSG Units 1 and 2 at 59°F with 1,500 hr/yr oil-firing per unit.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **5 lb/hr**	4. Equivalent Allowable Emissions: **5 lb/hr**
5. Method of Compliance (limit to 60 characters): **Fuel analysis for sulfur content per 40 CFR Part 75.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for natural gas-firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **101 lb/hr**	4. Equivalent Allowable Emissions: **101 lb/hr**
5. Method of Compliance (limit to 60 characters): **Fuel analysis for sulfur content per 40 CFR Part 75.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for distillate fuel oil -firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **21** lb/hour **99** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **21 lb/hr** Reference: **FDEP Permit PSD-FL-214A**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Hourly potential emission rate based on FDEP Permit PSD-FL-214A, Specific Conditions, B.1., distillate fuel oil-firing case. Annual potential emission rate is total for both CTG/HRSG Units 1 and 2 at 59°F with 1,500 hr/yr oil-firing per unit.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **5 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **10 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18 or 25A (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for natural gas-firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **21 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18 or 25A (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for distillate fuel oil -firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **H2SO4 (SAM)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22** lb/hour **39** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **22 lb/hr** Reference: **FDEP Permit PSD-FL-214A**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Hourly potential emission rate based on FDEP Permit PSD-FL-214A, Specific Conditions, B.1., distillate fuel oil-firing case. Annual potential emission rate is total for <u>both CTG/HRSG Units 1 and 2</u> at 59°F with 1,500 hr/yr oil-firing per unit.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1 lb/hr**	4. Equivalent Allowable Emissions: **1 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 8 (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for natural gas-firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **22 lb/hr**	4. Equivalent Allowable Emissions: **22 lb/hr**
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 8 (initial and annual)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for distillate fuel oil -firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **Beryllium (H021)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0049** lb/hour **0.007** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.0049 lb/hr** Reference: **FDEP Permit PSD-FL-214A**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Hourly potential emission rate based on FDEP Permit PSD-FL-214A, Specific Conditions, B.1., distillate fuel oil-firing case. Annual potential emission rate is total for <u>both CTG/HRSG Units 1 and 2</u> at 59°F with 1,500 hr/yr oil-firing per unit.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.0049 lb/hr**	4. Equivalent Allowable Emissions: **0.0049 lb/hr**
5. Method of Compliance (limit to 60 characters): **None required**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Emission limits applicable for distillate fuel oil-firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **Arsenic (H021)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0097** lb/hour **0.014** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.0097 lb/hr** Reference: **FDEP Permit PSD-FL-214A**	7. Emissions Method Code: **0**

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

Hourly potential emission rate based on FDEP Permit PSD-FL-214A, Specific Conditions, B.1., distillate fuel oil-firing case. Annual potential emission rate is total for both CTG/HRSG Units 1 and 2 at 59°F with 1,500 hr/yr oil-firing per unit.

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Rule**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.0097 lb/hr**	4. Equivalent Allowable Emissions: **0.0097 lb/hr**

5. Method of Compliance (limit to 60 characters):
None required

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

Emission limits applicable for distillate fuel oil-firing per FDEP Permit PSD-FL-214A, Specific Condition B.1.

FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [✔] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9 (initial and annual)**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Permit PSD-FL-214A, Specific Condition B.1.** **FDEP Rule 62-212.400(2)(f), F.A.C. (BACT)**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [✔] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Excess emissions resulting from startup, shutdown, or malfunction not-to-exceed 2 hours in any 24 hour period unless authorized by FDEP for a longer duration. Rule 62-210.700(1), F.A.C.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: **Columbia Scientific** Model Number: **5600**	Serial Number: **00395002**
5. Installation Date: **September 2001**	6. Performance Specification Test Date: **November 2001**
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **O_2**	2. Pollutant(s):
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: **M&C Products** Model Number: **PMA 100-L**	Serial Number: **00494001**
5. Installation Date: **September 2001**	6. Performance Specification Test Date: **November 2001**
7. Continuous Monitor Comment (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).**	

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

Supplemental Requirements

1. Process Flow Diagram [✔] Attached, Document ID: **Doc.II.C.3.** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [✔] Attached, Document ID: **Doc.III.J.3.** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID:________ [ ] Not Applicable [✔] Waiver Requested **See Air Construction Permit Application**
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested **To be provided with stack test report.**
5. Compliance Test Report [ ] Attached, Document ID: **To Be Provided** [ ] Previously submitted, Date: [ ] Not Applicable **Note: Compliance testing will be conducted during December 2001.**
6. Procedures for Startup and Shutdown [✔] Attached, Document ID: **Doc.III.J.6.** [ ] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [✔] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [✔] Attached, Document ID: **Doc. III.J.11.** [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [✔] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [✔] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [✔] Not Applicable **Subject to 40 CFR Part 75 Acid Rain Program monitoring.**
15. Acid Rain Part Application (Hard-copy Required) [✔] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: **Doc. III.J.15.** [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

NOTE:

EMISSION UNITS CTG/HRSG UNIT 1 AND CTG/HRSG UNIT 2 ARE IDENTICAL UNITS.

SECTION III EMISSIONS UNIT INFORMATION PROVIDED FOR EU 001 (CTG/HRSG UNIT 1) IS ALSO APPLICABLE TO EU 002 (CTG/HRSG UNIT 2).

EMISSIONS UNIT INFORMATION SECTIONS 2 THROUGH 7 ARE IDENTICAL TO SECTION 1, WITH THE EXCEPTION OF IDENTIFICATION NUMBERS.

ATTACHMENT I

APPLICABLE REGULATIONS

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 1 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 60 - Standards of Performance for New Stationary Sources.				
Subpart A - General Provisions				
Notification and Recordkeeping	'60.7(b) - (h)		CTG1 & CTG2	General recordkeeping and reporting requirements.
Performance Tests	'60.8		CTG1 & CTG2	Conduct performance tests as required by EPA or FDEP. **(potential future requirement)**
Compliance with Standards	'60.11(a) thru (d), and (f)		CTG1 & CTG2	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	'60.12		CTG1 & CTG2	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	'60.13(a), (b), (d), (e), and (h)		CTG1 & CTG2	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	'60.19		CTG1 & CTG2	General procedures regarding reporting deadlines.
Subpart Kb - Standard of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984				
40 CFR Part 60 Subpart Kb	'60.116b(b)		TK-1	The 1.35 MM gallon distillate fuel oil storage tank at the PCGS has a capacity greater than 151 m^3 (39,889.98 gallons) and stores a liquid with a maximum true vapor pressure less than 3.5 kPa (0.51 psia). With the exception of '60.116b(b)

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 2 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
				and (c), such storage tanks are exempt from the General Provisions (40 CFR Part 60, Subpart A) and the provisions of Subpart Kb pursuant to '60.110b(c). '60.116b(b) requires that records showing the dimensions of the storage tanks and an analysis of tank capacity be maintained and readily accessible onsite. '60.116b(c) is not applicable because it only applies to storage vessels either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m^3 (19,812.9 gallons) but less than 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa (2.17 psia).
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Standards for Nitrogen Oxides	'60.332(a)(1) and (b), (f), and (i)		CTG1 & CTG2	Establishes NO_x limit of 75 ppmv at 15% (with corrections for heat rate and fuel bound nitrogen) for electric utility stationary gas turbines with peak heat input greater than 100 MMBtu/hr.
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Standards for Sulfur Dioxide	'60.333		CTG1 & CTG2	Establishes exhaust gas SO_2 limit of 0.015 percent by volume (at 15% O_2, dry) and maximum fuel sulfur content of 0.8 percent by weight.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Monitoring Requirements	'60.334(a)		CTG1 & CTG2	Requires continuous monitoring of fuel consumption and ratio of water to fuel being fired in the turbine. Monitoring system must be accurate to "5.0 percent. Applicable to CTs using water injection for NO_x control.
Monitoring Requirements	'60.334(b)(2) and (c)		CTG1 & CTG2	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	'60.335		CTG1 & CTG2	Specifies monitoring procedures and test methods.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts B, C, Cb, Cc, Cd, Ce, D, Da, Db, Dc, E, Ea, Eb, Ec, F, G, H, I, J, K, Ka, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW.		X		None of the listed NSPS' contain requirements which are applicable to the PCGS emission units.
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants: Subparts A, B, C, D, E, F, H, I, J, K, L, M, N, O, P, Q, R, T, V, W, Y, BB, and FF.		X		None of the listed NESHAPS' contain requirements which are applicable to the PCGS emission units.
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, XXX, CCCC, GGGG, and VVVV.		X		None of the listed NESHAPS' contain requirements which are applicable to the PCGS emission units.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 72 - Acid Rain Program Permits				
Subpart A - Acid Rain Program General Provisions				
Standard Requirements	'72.9 excluding '72.9(c)(3)(i), (ii), and (iii), and '72.9(d)		CTG1 & CTG2	General Acid Rain Program requirements. SO_2 allowance program requirements start January 1, 2000 **(future requirement)**.
Subpart B - Designated Representative				
Designated Representative	'72.20 - '72.24		CTG1 & CTG2	General requirements pertaining to the Designated Representative.
Subpart C - Acid Rain Application				
Requirements to Apply	'72.30(a), (b)(2)(ii), (c), and (d)		CTG1 & CTG2	Requirement to submit a complete Phase II Acid Rain permit application to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation. Requirement to submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted. **(future requirement)**.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Application Shield	'72.32		CTG1 & CTG2	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.
Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	'72.40(a)(1)		CTG1 & CTG2	General SO_2 compliance plan requirements.
General	'72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to the PCGS CTGs.
Subpart E - Acid Rain Permit Contents				
Permit Shield	'72.51		CTG1 & CTG2	Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
Subpart H - Permit Revisions				
Fast-Track Modifications	'72.82(a) and (c)		CTG1 & CTG2	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	'72.90		CTG1 & CTG2	Requirement to submit an annual compliance report. **(future requirement)**

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	'75.5		CTG1 & CTG2	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	'75.10		CTG1 & CTG2	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	'75.11(d)(2)		CTG1 & CTG2	SO_2 continuous monitoring requirements for gas- and oil-fired units. Appendix D election will be made.
Specific Provisions for Monitoring NO_x Emissions	'75.12(a) and (b)		CTG1 & CTG2	NO_x continuous monitoring requirements for coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units
Specific Provisions for Monitoring CO_2 Emissions	'75.13(b)		CTG1 & CTG2	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	'75.14(d)		CTG1 & CTG2	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	'75.20(b)		CTG1 & CTG2	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	'75.20(c)		CTG1 & CTG2	Recertification procedure requirements. **(potential future requirement)**

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Quality Assurance and Quality Control Requirements	'75.21 except '75.21(b)		CTG1 & CTG2	General QA/QC requirements (excluding opacity).
Reference Test Methods	'75.22		CTG1 & CTG2	Specifies required test methods to be used for recertification testing (**potential future requirement**).
Out-Of-Control Periods	'75.24 except '75.24(e)		CTG1 & CTG2	Specifies out-of-control periods and required actions to be taken when out-of-control periods occur (excluding opacity).
Subpart D - Missing Data Substitution Procedures				
General Provisions	'75.30(a)(3), (b), (c)		CTG1 & CTG2	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	'75.32		CTG1 & CTG2	Monitor data availability procedure requirements.
Standard Missing Data Procedures	'75.33(a) and (c)		CTG1 & CTG2	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	'75.50(a), (b), (d), and (e)(2)		CTG1 & CTG2	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	'75.53(a), (b), (c), and (d)(1)		CTG1 & CTG2	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	'75.54(a), (b), (d), and (e)(2)		CTG1 & CTG2	Requirements pertaining to general recordkeeping.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
General Recordkeeping Provisions for Specific Situations	'75.55(c)		CTG1 & CTG2	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	'75.56(a)(1), (3), (5), (6), and (7)		CTG1 & CTG2	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	'75.56(b)(1)		CTG1 & CTG2	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	'75.60		CTG1 & CTG2	General reporting requirements.
Notification of Certification and Recertification Test Dates	'75.61(a)(1) and (5), (b), and (c)		CTG1 & CTG2	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.
Subpart G - Reporting Requirements				
Recertification Application	'75.63		CTG1 & CTG2	Requires submittal of a recertification application within 30 days after completing the recertification test. **(potential future requirement)**
Quarterly Reports	'75.64(a)(1) - (5), (b), (c), and (d)		CTG1 & CTG2	Quarterly data report requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 9 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program		X		The Acid Rain Nitrogen Oxides Emission Reduction Program only applies to coal-fired utility units that are subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II.
40 CFR Part 77 - Excess Emissions				
Offset Plans for Excess Emissions of Sulfur Dioxide	'77.3		CTG1 & CTG2	Requirement to submit offset plans for excess SO_2 emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO_2 emissions. Required contents of offset plans are specified **(potential future requirement)**.
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	'77.5(b)		CTG1 & CTG2	Requirement for the Designated Representative to hold enough allowances in the appropriate compliance subaccount to cover deductions to be made by EPA if a timely and complete offset plan is not submitted or if EPA disapproves a proposed offset plan **(potential future requirement)**.
Penalties for Excess Emissions of Sulfur Dioxide	'77.6		CTG1 & CTG2	Requirement to pay a penalty if excess emissions of SO_2 occur at any affected unit during any year **(potential future requirement)**.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 10 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		The PCGS will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		PCGS personnel will not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing will be conducted by persons who comply with Subpart B requirements.
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		The PCGS will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		The PCGS will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	'82.154	X		PCGS personnel will not maintain, service, repair, or dispose of any appliances. All such activities will be performed by independent parties in compliance with '82.154 prohibitions.
Required Practices	'82.156 except '82.156(i)(5), (6), (9), (10), and (11)	X		Contractors will maintain, service, repair, and dispose of any appliances in compliance with '82.156 required practices.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 11 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart F - Recycling and Emissions Reduction				
Required Practices	'82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by '82.152- any device which contains and uses a Class I or II substance as a refrigerant and which is used for household or commercial purposes, including any air conditioner, refrigerator, chiller, or freezer	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	'82.161	X		PCGS personnel will not maintain, service, repair, or dispose of any appliances and therefore are not subject to technician certification requirements.
Certification By Owners of Recovery and Recycling Equipment	'82.162	X		PCGS personnel will not maintain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 12 of 12)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Reporting and Recordkeeping Requirements	'82.166(k), (m), and (n)		Appliances as defined by '82.152	Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep servicing records documenting the date and type of service, as well as the quantity of refrigerant added.
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 64 - Regulations on Compliance Assurance Monitoring for Major Stationary Sources		X		Exempt per '64.2(b)(1)(iii) since CTG1 and CTG2 will meet Acid Rain Program monitoring requirements.
40 CFR Part 68 - Provisions for Chemical Accident Prevention			Ammonia Storage	Subject to provisions of 40 CFR Part 68 due to ammonia storage.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 49, 53, 54, 55, 56, 57, 58, 59, 62, 65, 66, 67, 69, 71, 74, 76, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 600, and 610		X		The listed regulations do not contain any requirements which are applicable to the PCGS.

Source: ECT, 2001.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 1 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-4, F.A.C. - Permits: Part I General					
Scope of Part I	62-4.001, F.A.C.		X		Contains no applicable requirements.
Definitions	62-4.020, .021, F.A.C.		X		Contains no applicable requirements.
Transferability of Definitions	62-4.021, .021, F.A.C.		X		Contains no applicable requirements.
General Prohibition	62-4.030, F.A.C		X		All stationary air pollution sources must be permitted, unless otherwise exempted.
Exemptions	62-4.040, F.A.C		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits	62-4.050, F.A.C.		X		General permitting requirements.
Surveillance Fees	62-4.052, F.A.C.	X			Not applicable to air emission sources.
Permit Processing	62-4.055, F.A.C.		X		Contains no applicable requirements.
Consultation	62-4.060, F.A.C.		X		Consultation is encouraged, not required.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C		X		Establishes standard procedures for FDEP.
Modification of Permit Conditions	62-4.080, F.A.C	X			Application is for initial Title V permit. Modification of permit conditions is not being requested.
Renewals	62-4.090, F.A.C.		X		Establishes permit renewal criteria. Additional criteria are cited at 62-213.-430(3), F.A.C. **(future requirement)**

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 2 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Suspension and Revocation	62-4.100, F.A.C.		X		Establishes permit suspension and revocation criteria.
Financial Responsibility	62-4.110, F.A.C.		X		Contains no applicable requirements.
Transfer of Permits	62-4.120, F.A.C.	X			A sale or legal transfer of a permitted facility is not included in this application.
Plant Operation - Problems	62-4.130, F.A.C.		X		Immediate notification is required whenever the permittee is temporarily unable to comply with any permit condition. Notification content is specified. **(potential future requirement)**
Review	62-4.150, F.A.C.		X		Contains no applicable requirements.
Permit Conditions	62-4.160, F.A.C.		X		Contains no applicable requirements.
Scope of Part II	62-4.2.00, F.A.C.		X		Contains no applicable requirements.
Construction Permits	62-4.210, F.A.C.	X			General requirements for construction permits.
Operation Permits for New Sources	62-4.220, F.A.C.		X		General requirements for initial new source operation permits.
Water Permit Provisions	62-4.240 - 250, F.A.C.	X			Contains no applicable requirements.
Chapter 62-17, F.A.C. - Electrical Power Plant Siting			X		Power Plant Siting Act provisions.
Chapter 62-102, F.A.C. - Rules of Administrative Procedure - Rule Making			X		General administrative procedures.
Chapter 62-103, F.A.C. - Rules of Administrative Procedure - Final Agency Action			X		General administrative procedures.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 3 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-204, F.A.C. - State Implementation Plan					
State Implementation Plan	62-204.100, .200, .220(1)-(3), .240, .260, .320, .340, .360, .400, and .500, F.A.C.	X			Contains no applicable requirements.
Ambient Air Quality Protection	62-204.220(4), F.A.C.		X		Assessments of ambient air pollutant impacts must be made using applicable air quality models, data bases, and other requirements approved by FDEP and specified in 40 CFR Part 51, Appendix W.
State Implementation Plan	62-204.800(1) - (6), F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800(7)(a), (b)16.,(b)39., (c), (d), and (e), F.A.C.			CTG1, CTG2, TK-1	NSPS Subparts Kb and GG; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(8) - (13), (15), (17), (20), and (22) F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800 (14), (16), (18), (19), F.A.C.		X	CTG1 & CTG2	Acid Rain Program; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(21), F.A.C.		X		Protection of Stratospheric Ozone; see Table A-1 for detailed federal regulatory citations.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 4 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-210, F.A.C. - Stationary Sources - General Requirements					
Purpose and Scope	62-210.100, F.A.C.		X		Contains no applicable requirements.
Definitions	62-210.200, F.A.C.		X		Contains no applicable requirements.
Small Business Assistance Program	62-210.220, F.A.C.	X			Contains no applicable requirements.
Permits Required	62-210.300(1) and (3), F.A.C.		X		Exemptions from permitting specified for certain facilities and sources.
Permits Required	62-210.300(2), F.A.C.		X		Air operation permit required.
Air General Permits	62-210.300(4), F.A.C.	X			Not applicable to the PCGS.
Notification of Startup	62-210.300(5), F.A.C.	X			Sources which have been shut down for more than one year shall notify the FDEP prior to startup.
Emission Unit Reclassification	62-210.300(6), F.A.C.		X		Emission unit reclassification **(potential future requirement)**
Public Notice and Comment					
Public Notice of Proposed Agency Action	62-210.350(1), F.A.C.		X		All permit applicants required to publish notice of proposed agency action.
Additional Notice Requirements for Sources Subject to Prevention of Significant Deterioration or Nonattainment Area New Source Review	62-210.350(2), F.A.C.	X			Additional public notice requirements for PSD and nonattainment area NSR applications.
Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources	62-210.350(3), F.A.C.		X		Notice requirements for Title V operating permit applicants.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 5 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Public Notice Requirements for FESOPS and 112(g) Emission Sources	62-210.350(4) and (5), F.A.C.	X			Not applicable to the PCGS.
Administrative Permit Corrections	62-210.360, F.A.C.	X			An administrative permit correction is not requested in this application.
Reports					
Notification of Intent to Relocate Air Pollutant Emitting Facility	62-210.370(1), F.A.C.	X			Project does not have any relocatable emission units.
Annual Operating Report for Air Pollutant Emitting Facility	62-210.370(3), F.A.C.		X		Specifies annual reporting requirements. **(future requirement)**.
Stack Height Policy	62-210.550, F.A.C.		X		Limits credit in air dispersion studies to good engineering practice (GEP) stack heights for stacks constructed or modified since 12/31/70.
Circumvention	62-210.650, F.A.C.		X		An applicable air pollution control device cannot be circumvented and must be operated whenever the emission unit is operating.
Excess Emissions	62-210.700(1), F.A.C.		X		Excess emissions due to startup, shut down, and malfunction are permitted for no more than two hours in any 24 hour period unless specifically authorized by the FDEP for a longer duration.
Excess Emissions	62-210.700(2) and (3), F.A.C.	X			Not applicable to the PCGS.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 6 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Excess Emissions	62-210.700(4), F.A.C.		X		Excess emissions caused entirely or in part by poor maintenance, poor operations, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction are prohibited.
Excess Emissions	62-210.700(5), F.A.C.		X		Contains no applicable requirements.
Excess Emissions	62-210.700(6), F.A.C.		X		Excess emissions resulting from malfunctions must be reported to the FDEP in accordance with 62-4.130, F.A.C. **(potential future requirement)**.
Forms and Instructions	62-210.900, F.A.C.		X		Contains AOR requirements.
Notification Forms for Air General Permits	62-210.920, F.A.C.	X			Contains no applicable requirements.
Chapter 62-212, F.A.C. - Stationary Sources - Preconstruction Review					
Purpose and Scope	62-212.100, F.A.C.		X		Contains no applicable requirements.
General Preconstruction Review Requirements	62-212.300, F.A.C.	X			General air construction permit requirements.
Prevention of Significant Deterioration	62-212.400, F.A.C.	X			PSD permit requirements.
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			Project is not located in a nonattainment area or a nonattainment area of influence.
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 7 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to the PCGS.
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.		X		Contains no applicable requirements.
Annual Emissions Fee	62-213.205(1), (4), and (5), F.A.C.		X		Annual emissions fee and documentation requirements. **(future requirement)**
Annual Emissions Fee	62-213.205(2) and (3), F.A.C.	X			Contains no applicable requirements.
Title V Air General Permits	62-213.300, F.A.C.	X			No eligible facilities
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required.
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met **(potential future requirement)**.
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be implemented pending permit revision if specific criteria are met **(potential future requirement)**.
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			CTG1 & CTG2	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 8 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Applications	62-213.420(1)(a)2. and (1)(b), (2), (3), and (4), F.A.C.		X		Title V operating permit application required no later than 180 days after commencing operation.
Permit Issuance, Renewal, and Revision					
Action on Application	62-213.430(1), F.A.C.		X		Contains no applicable requirements.
Permit Denial	62-213.430(2), F.A.C.		X		Contains no applicable requirements.
Permit Renewal	62-213.430(3), F.A.C.		X		Permit renewal application requirements **(future requirement)**.
Permit Revision	62-213.430(4), F.A.C.		X		Permit revision application requirements **(potential future requirement)**.
EPA Recommended Actions	62-213.430(5), F.A.C.		X		Contains no applicable requirements.
Insignificant Emission Units	62-213.430(6), F.A.C.		X		Contains no applicable requirements.
Permit Content	62-213.440, F.A.C.		X		Agency procedures, contains no applicable requirements.
Permit Review by EPA and Affected States	62-213.450, F.A.C.		X		Agency procedures, contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and conditions.
Forms and Instructions	62-213.900, F.A.C.		X		Contains annual emissions fee form requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 9 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-214CRequirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	'62-214.100, F.A.C.		X		Contains no applicable requirements.
Applicability	'62-214.300, F.A.C.		X		Project includes Acid Rain affected units, therefore compliance with '62-213 and '62-214, F.A.C., is required.
Applications	'62-214.320, F.A.C.			CTG1 & CTG2	Acid Rain application requirements. Application for new units are due at least 24 months before the later of 1/1/2000 or the date on which the unit commences operation.
Acid Rain Compliance Plan and Compliance Options	'62-214.330(1)(a), F.A.C.			CTG1 & CTG2	Acid Rain compliance plan requirements. Sulfur dioxide requirements become effective the later of 1/1/2000 or the deadline for CEMS certification pursuant to 40 CFR Part 75. **(future requirement)**
Exemptions	'62-214.340, F.A.C.		X		An application may be submitted for certain exemptions **(potential future requirement)**.
Certification	'62-214.350, F.A.C.			CTG1 & CTG2	The designated representative must certify all Acid Rain submissions. **(future requirement)**
Department Action on Applications	'62-214.360, F.A.C.		X		Contains no applicable requirements.
Revisions and Administrative Corrections	'62-214.370, F.A.C.			CTG1 & CTG2	Defines revision procedures and automatic amendments **(potential future requirement)**.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 10 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Acid Rain Part Content	'62-214.420, F.A.C.			CTG1 & CTG2	Agency procedures, contains no applicable requirements.
Implementation and Termination of Compliance Options	'62-214.430, F.A.C.			CTG1 & CTG2	Defines permit activation and termination procedures **(potential future requirement)**.
Chapter 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to the PCGS.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to the PCGS.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to the PCGS.
Chapter 62-256 - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.		X		Contains no applicable requirements.
Definitions	62-256.200, F.A.C.		X		Contains no applicable requirements.
Prohibitions	**62-256.300, F.A.C.**[1]		X		Prohibits open burning.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.
Land Clearing	**62-256.500, F.A.C.**[1]		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	**62-256.600, F.A.C.**[1]		X		Prohibits industrial open burning

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 11 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Open Burning allowed	62-256.700, F.A.C.		X		Specifies allowable open burning activities. **(potential future requirement)**
Effective Date	62-256.800, F.A.C.		X		Contains no applicable requirements.
Chapter 62-257 - Asbestos Fee	62-257, F.A.C.	X			Not applicable to the PCGS.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to the PCGS
Chapter 62-296 - Stationary Source - Emission Standards					
Purpose and Scope	62-296.100, F.A.C.		X		Contains no applicable requirements
General Pollutant Emission Limiting Standard, Volatile Organic Compounds Emissions	62-296.320(1), F.A.C.		X		Known and existing vapor control devices must be applied as required by the Department.
General Pollutant Emission Limiting Standard, Objectionable Odor Prohibited	62-296.320(2), F.A.C.		X		Objectionable odor release is prohibited.
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	**62-296.320(3), F.A.C.**[1]		X		Open burning in connection with industrial, commercial, or municipal operations is prohibited.
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.	X			PCGS does not have any applicable emission units. Combustion emission units are exempt per 62-296.320(4)(a)1a.
General Particulate Emission Limiting Standard, General Visible Emission Standard	62-296.320(4)(b), F.A.C.		X		Opacity limited to 20 percent, unless otherwise permitted. Test methods specified.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 12 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
General Particulate Emission Limiting Standard, Unconfined Emission of Particulate Matter	62-296.320(4)(c), F.A.C.		X		Reasonable precautions must be taken to prevent unconfined particulate matter emission.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.417, F.A.C.	X			None of the referenced standards are applicable to the PCGS.
Reasonably Available Control Technology (RACT) Volatile Organic Compounds (VOC) and Nitrogen Oxides (NO_x) Emitting Facilities	62-296.500 through 62-296.516, F.A.C.	X			Standards do not apply to new sources which have been subject to PSD review.
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO_x-Emitting Facilities	62-296.570, F.A.C.	X			Standards do not apply to new sources which have been subject to PSD review.
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			The PCGS is not located in a lead non-attainment area or a lead air quality maintenance area.
Reasonably Available Control Technology (RACT)CParticulate Matter	'62-296.700 through 62-296.712, F.A.C.	X			The PCGS is not located in a PM non-attainment area or a PM air quality maintenance area.
Chapter 62-297 - Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.		X		Contains no applicable requirements.
General Compliance Test Requirements	62-297.310, F.A.C.		X		Specifies general compliance test requirements.
Compliance Test Methods	62-297.401, F.A.C.		X		Contains no applicable requirements.
Supplementary Test Procedures	62-297.440, F.A.C.		X		Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 13 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Not applicable to the PCGS.
CEMS Performance Specifications	62-297.520, F.A.C.			CTG1 & CTG2	CEMS requirements
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.	X			Exceptions or alternate procedures have not been requested.

[1] - State requirement only; not federally enforceable.

Source: ECT, 2001.

DOCUMENT II. C. 1.

AREA MAP

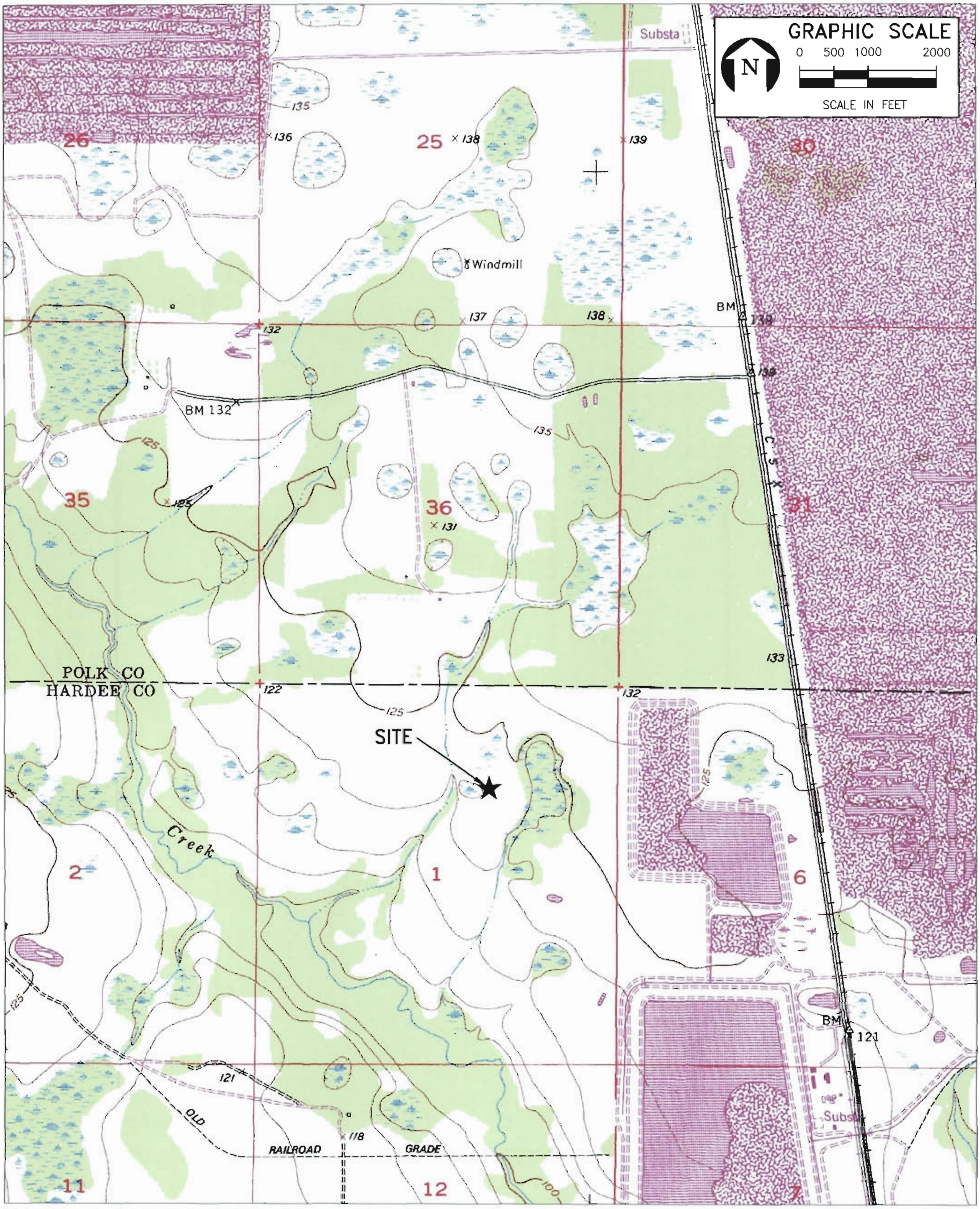

FIGURE 1.

SITE LOCATION MAP

PAYNE CREEK GENERATING STATION

Sources: USGS Quad: Baird, FL, 1987; ECT, 2001.

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

DOCUMENT II. C. 2.

FACILITY PLOT PLAN

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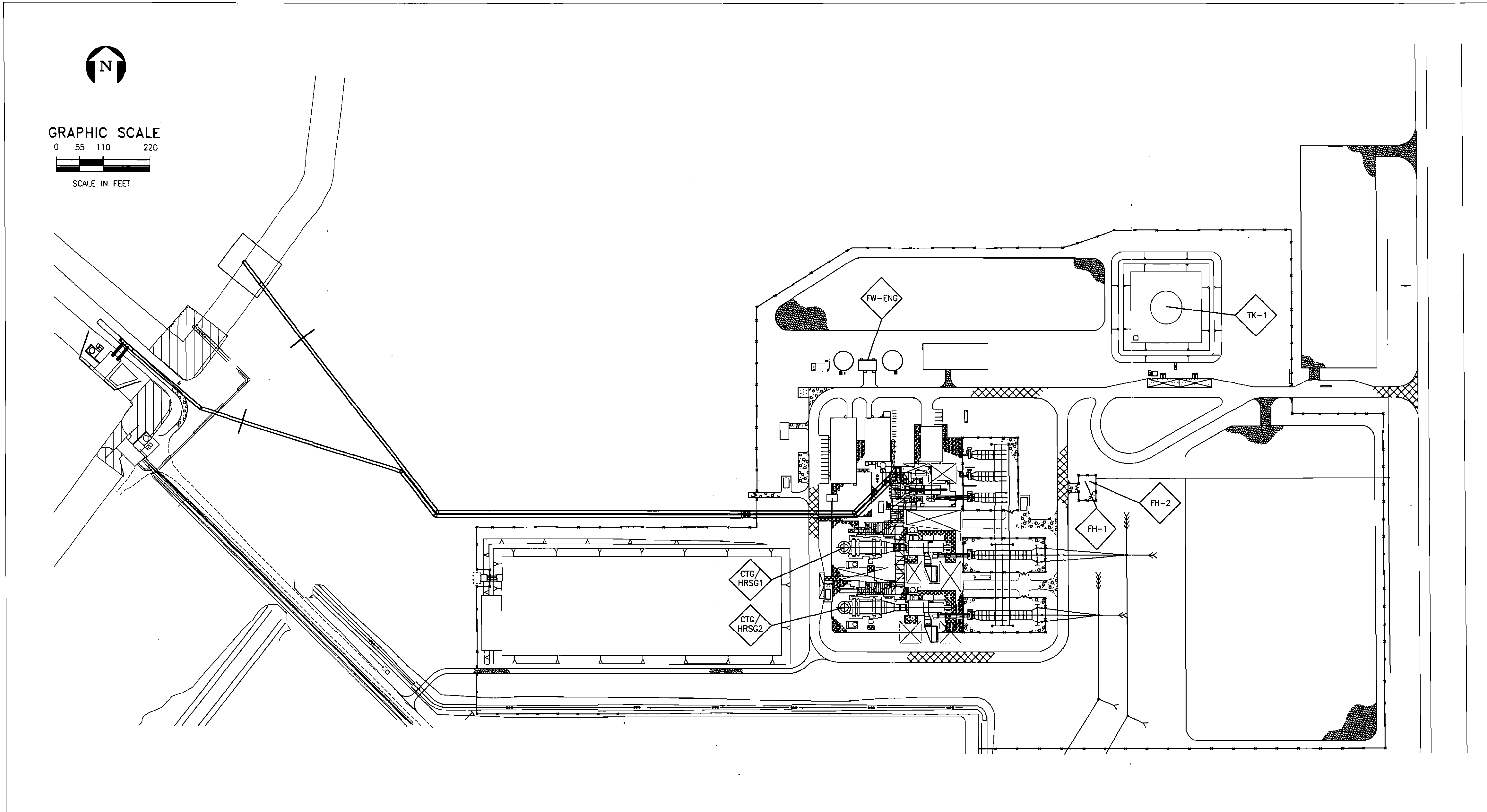


DOCUMENT II. C.2.

FACILITY PLOT PLAN

PAYNE CREEK GENERATING STATION

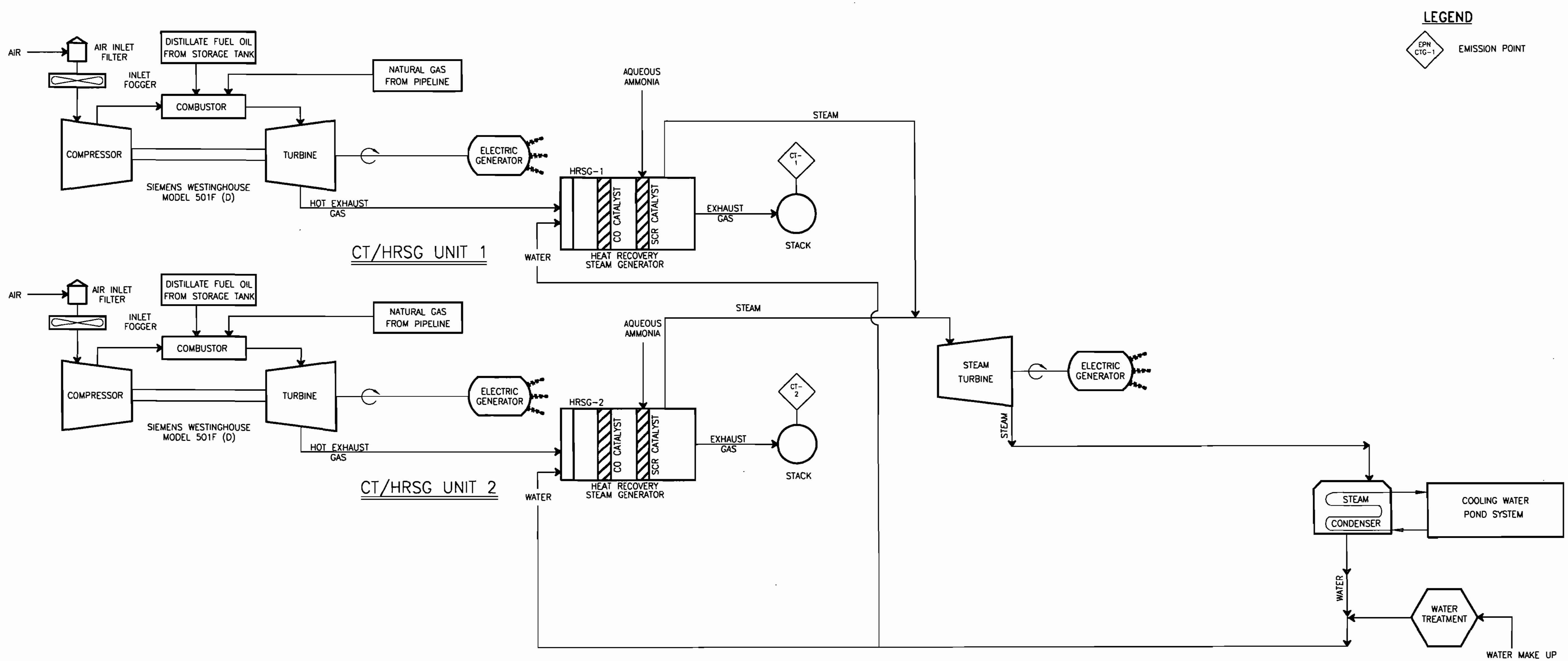
Sources: SECI, 2001; ECT, 2001.

Seminole Electric COOPERATIVE, INC.

IN PARTNERSHIP WITH THOSE WE SERVE

DOCUMENT II. C. 3.

PROCESS FLOW DIAGRAM



DOC. II. C. 3.

PROCESS FLOW DIAGRAM - PAYNE CREEK GENERATING STATION

Source: ECT, 2001.

Seminole Electric COOPERATIVE, INC.

IN PARTNERSHIP WITH THOSE WE SERVE

DOCUMENT II. C. 4.

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter emissions that may result from PCGS operations include:

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

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

- Chemical or water application to:
  - Unpaved roads
  - Unpaved yard areas

- Paving and maintenance of roads, parking areas and yards.
- Landscaping or planting of vegetation.
- Confining abrasive blasting where possible.
- Other techniques, as necessary.

DOCUMENT II. C. 8.

LIST OF PROPOSED INSIGNIFICANT ACTIVITIES

LIST OF PROPOSED INSIGNIFICANT ACTIVITIES

1. Internal combustion engines in boats, aircraft, and vehicles used for transportation of passengers or freight.

2. Vacuum pumps in laboratory operations.

3. Equipment used for steam cleaning.

4. Belt or drum sanders having a total sanding surface of 5 square feet (ft^2) or less and other equipment used exclusively on wood or plastics or their products having a density of 20 pounds per cubic foot or more.

5. Equipment used exclusively for space heating, other than boilers.

6. Laboratory equipment used exclusively for chemical or physical analyses.

7. Brazing, soldering or welding equipment.

8. 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.
   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.

9. One or more heating units, 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.
   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.

LIST OF PROPOSED INSIGNIFICANT ACTIVITIES
(Continued, Page 2 of 3)

c. Fuel for the heating units, general purpose internal combustion engines, and other combustion devices that would be exempted is limited to natural gas, diesel fuel, gasoline and propane.

10. Fire and safety equipment.

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

12 Surface coating operations utilizing only coatings containing 5.0 percent or less VOCs, by volume.

13. Degreasing units using heavier-than-air vapors exclusively, except any such unit using or emitting any substance classified as a hazardous air pollutant.

14. Petroleum lubrication systems.

15. Application of fungicide, herbicide, or pesticide.

16. Non-halogenated solvent storage and cleaning operations, provided the solvents contain none of the hazardous air pollutants listed at Rule 62-210.200, F.A.C.

17. Vehicle refueling operations and associated fuel storage.

18. Storage tanks less than 250 gallons.

19. General plant maintenance activities including, but not limited to, welding, grinding, and general vehicle repair (excluding air-conditioning systems).

20. Water treatment equipment

LIST OF PROPOSED INSIGNIFICANT ACTIVITIES
(Continued, Page 3 of 3)

21. Any emission unit or activity that would:

    a. Not be subject to any unit-specific applicable requirement.
    b. Neither emit nor have the potential to emit:
        (i) 500 pounds per year or more 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.
        (iv) 5.0 tons per year or more of any other regulated pollutant.

22. Distillate fuel oil truck unloading equipment.

23. One,1.35 million gallon distillate fuel oil storage tank.

24. Two 5.0 MMBtu/hr natural gas-fired fuel gas heaters.

25. One 275 BHP fire water pump diesel engine.

26. Oil/water separators.

27. Lube oil tank vents.

28. Architectural (equipment) maintenance painting.

29. Vehicular traffic on plant roadways and grounds.

Sand blasting and abrasive grit blasting where temporary total enclosures are used to contain particulate matter emissions.

DOCUMENT II. C. 13.

RISK MANAGEMENT
PLAN VERIFICATION

ECT
Environmental Consulting & Technology, Inc.

EPA United States Environmental Protection Agency

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

Jim Pittman
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, FL 33688-2000

October 25, 2001

EPA Facility ID#:	**1000 0017 6891**
Postmark Date:	**10/23/2001**
Anniversary Date:	**10/23/2006**

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.

If you have any questions, please call one of the following numbers:

(1) For RMP rule interpretation questions, call the EPCRA Hotline at (800) 424-9346 or (703) 412-9810 (in the D.C. Metro area).

(2) For RMP*Submit installation and software questions, or information on the status of your RMP, contact the RMP Reporting Center at (703) 816-4434, or write to the:

RMP Reporting Center
P.O. Box 3346
Merrifield, VA 22116-3346

(3) For more information on the Risk Management Program, you can contact your Implementing Agency. Your Implementing Agency is

Florida Department of Community Affairs, 2555 Shumard Oak Boulevard, Tallahassee, FL, 32399, Phone: 850-413-9970.

Thank you for your cooperation in this matter.

Sincerely,

RMP Reporting Center

Enclosure:
Risk Management Plan (if submitted on paper)

DOCUMENT II. C. 14. AND 15.

COMPLIANCE REPORT AND PLAN
COMPLIANCE CERTIFICATION

Environmental Consulting & Technology, Inc.

COMPLIANCE REPORT, PLAN, AND CERTIFICATION

1. Compliance Report and Plan

Attachment A-1 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 consistent with FDEP Rule 62-213.440(3)(a)2., F.A.C.

3. Compliance Certification

I, the undersigned, am the responsible official as defined in Chapter 62-210.200(247), F.A.C., of the Title V 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 report are true, accurate, and complete.

Michael P. Opalinski Director of Environmental Affairs	Date

Note: A signed Compliance Report and Plan and Compliance Certification will be submitted following completion of the initial compliance tests planned for December 2001.

DOCUMENT III. J. 2.

FUEL ANALYSES

Table 1 – Expected Natural Gas Analysis

Constituents	Percent by Volume
Methane (CH_4)	83.4%
Ethane (C_2H_6)	15.8%
Nitrogen (N_2)	0.8%
Sulfur (S), max.	0.2 grains/100 SCF

Table 2 – Expected Fuel Oil Analysis

Constituents	Percent by Weight
Carbon (C)	86.139%
Hydrogen (H)	13.8%
Sulfur (S)	0.05%
Fuel Bound Nitrogen (FBN)	0.015%
Ash	0.001%

DOCUMENT III. J. 6.

PROCEDURES FOR STARTUP AND SHUTDOWN

Environmental Consulting & Technology, Inc.

Payne Creek Generating Station Project
501F 2x1
Combined Cycle Operating Philosophy

Revision: 7a
Prepared by: R. Thompson, C. Hookham, et al

This procedural outline description is conceptual and is intended to be a guideline for the overall combined cycle control philosophy relative to Payne Creek's startup, shutdown, trips, restart, transition, transient, and 100% ST bypass operations. All values shown below are typical values and are subject to change. This document is not a substitute for other project specific documents that have been issued to support commissioning and O & M efforts.

EQUIPMENT

Gas turbine (GT):	2 - 501F ECONOPAC, dual fuel capability
GT rotor air cooling:	1 - rotor air/ambient air heat exchanger (a.k.a., "fin-fan cooler") per GT
Steam turbine (ST):	1 - SFHP; IP/LP axial exhaust condensing
HRSG:	2 - Vogt-NEM 3 pressure, reheat, horizontal, natural circulation, with selective catalytic reduction and carbon monoxide catalyst.
BFP:	2 x 100% HRSG flow capacity [2 BFPs per HRSG]
Condenser:	1 - axial exhaust configuration, deaerating type
Condensate pumps:	3 x 50% station system capacity
Circulating water pumps:	2 x 50% station system capacity
Teleperm XP Plant Controls	

DEFINITIONS:

1. OCI = Overland Contracting, Inc., a subsidiary of Black & Veatch and Consortium partner with SWPC.
2. STIB = Steam Turbine Instruction Book.
3. not used.
4. The start-up vent valves, supplied by the HRSG supplier, shall be sized for low pressure, low flow conditions during start-up. These valves are not pressure relief valves nor are they intended, by design, to be. To prevent any misconceptions of this intent, the DCS should contain logic that prohibits operation of these valves during all plant operations, except cold, warm, and hot start-ups.
5. TV = Steam turbine HP Throttle Valve
6. GV = Steam turbine HP Governor Valve
7. RSV = Steam turbine IP Reheat Stop Valve
8. IV = Steam turbine IP Intercept Valve
9. ISV = Steam turbine LP Induction Stop Valve
10. ICV = Steam turbine LP Induction Control Valve
11. VNI = Vogt-NEM, Inc., supplier of the heat recovery steam generators to the station via SWPCBFP = segmental ring HRSG feedwater pumps, manufactured by KSB on behalf of SWPC
12. DCS = Teleperm XP distributed control system (DCS), manufactured by SWPC, including the TXP(digital electrohydraulic control) for the steam turbine
13. "HRSG out of service" = ~~(by SWPC)~~ not providing steam to the ST.
14. 16. "HRSG in service" = ~~(by SWPC~~ *providing steam to the ST.*
15. VWO – steam turbine admission valves wide open

REFERENCES:

1. OCI Feedwater P&ID
2. OCI Condensate P&ID
3. OCI Main Steam P&ID
4. OCI Reheat Steam P&IDs
5. OCI LP Steam P&ID
6. VNI HRSG P&IDs
7. SWPC Controls (GTG, STG, and BOP)
8. VNI HRSG Operating & Maintenance Manual and Startup Procedures
9. KSB BFP Operating & Maintenance Manual.
10. Teleperm XP Manuals
11. **Bypass Control Curves**
12. **OCI Prepared System Descriptions**
13. **SWPC Prepared Instruction Books**

INTRODUCTION

The Payne Creek Generating Station (PCGS) is a two-on-one, combustion turbine based electrical power generating station situated in Bowling Green, Florida, and constructed by the Consortium of SWPC and OCI on behalf of Seminole Electric Cooperative, Inc. (the Owner). The station has a guaranteed generating capacity of 488.2 megawatts (MW) at 95 degrees F while combusting natural gas. While principally designed for natural gas operations, the station combustion turbines are also configured to combust fuel oil. Combustion turbine exhaust is passed through triple pressure HRSGs to produce steam, which is directed to the axially exhausting twin-casing steam turbine. To meet air emissions limitations, the HRSGs were outfitted with both selective catalytic (NOx) reduction and carbon monoxide (CO) catalyst sections. Water pumped to the surface condenser for condensing steam is provided by a once-through system with water from the existing cooling water reservoir, shared with the neighboring Hardee Power Station.

Power generated by the three air-cooled PCGS generators at 18 kiloVolts (kV) is stepped up to 230 kV in the respective generator stepup transformers and transmitted through the PCGS switchyard to the Hardee Power Station switchyard and grid.

Operation of the PCGS requires integrated and sequenced operation of numerous balance-of-plant (BOP) mechanical and electrical systems. Given that current Owner plans call for base load operation during summer and winter seasons and cycling operation during spring and fall seasons, it is critical that certain proper sequences be followed. The following provides a general list of prerequisites to first combustion turbine cold start.

BOP:

Prior to startup of the Payne Creek Generating Station, a number of conditions must be present and balance of plant systems either operating or functionally able to start. In particular, the 230 kV transmission lines from the Hardee Power Station switchyard must be energized up to the three high-side generator circuit breakers in the Payne Creek switchyard and supplying power to at least one of two station auxiliary transformers. All associated protective relaying must be operational. There must also be sufficient water in the shared cooling water reservoir, with minimum water elevation of 122'-0". Natural gas at sufficient pressure must be available at the Pressure Regulating Station, or a sufficient supply of fuel oil must be available in the station fuel oil tank. Startup should also be preceded by filling of the service/fire water tank via the Hardee Power Station wells, and topping of all chemical supply tanks (e.g., aqueous ammonia, sodium hypochlorite, cycle feed chemicals, acid/caustic). The condenser hotwell shall also be filled to at least the normal water level via the Water Treatment and Cycle Makeup and Storage Systems

The following balance of plant systems must be available, functionally able to perform, and placed into operation prior to initiation of combined cycle operations (refer to System Descriptions for additional data):

- Distributed Control System (DCS)
- Continuous Emissions Monitoring
- Station AC, DC, and UPS Supply and Distribution Systems (multiple systems)
- Circulating Water
- Closed Cycle Cooling Water
- Fire Protection (all subsystems)
- Service Water Pretreatment
- Service Water
- Compressed Air (Station and Control Air)
- Cycle Makeup and Storage
- Condenser and Condenser Air Extraction
- Fuel Gas or Fuel Oil (depending on fuel selection)
- Water Treatment
- Circulating Water Chemical Feed
- Cycle Chemical Feed
- Steam and Water Sampling and Analysis
- HRSG Blowdown
- HRSG NOx Reduction
- Chemical Waste Drainage and Treatment
- Wastewater Collection and Treatment
- All steam piping systems, with drains and vents open

Prior to initiating station operations, the Condensate system is started (with cross-ties to the Feedwater system) to fill the HRSG high, intermediate, and low pressure economizers and drums associated with the first CT/G to be operated (and second HRSG drums if 2x1 operations are planned). All auxiliaries associated with the first combustion turbine/generator and steam turbine/generator, including lube oil, control oil, and control air (and ST seals and drains) systems must be available and operational prior to cold startup.

<u>CT</u>:

See the SWPC Instruction Books for CT Econopac prerequisites and general guidance.

STATION STARTUP AND OPERATION

Startup of the Payne Creek Generating Station may be occur in one of three different states depending on the thermal conditions of the turbine/generator sets and HRSGs. Subsequent operations of the Station may occur in 1x1 (one GT and ST operating), 2x1, or GT operation only configurations, depending on SECI's generation needs. Irregardless of thermal conditions or desired configuration, startup is accomplished by first bringing a single GT/HRSG train on-line and to load. Only one GT starting motor may be run at one time.

The following subsections provide procedural information on startup and operations, in various thermal states and configurations, with natural gas firing of the GT(s). A cold start of the station to a 2x1 configuration represents the most comprehensive startup process and is initially described. Each subsection first describes bounding thermal conditions for reference. Later subsections describe transition from 1x1 to 2x1 configuration, response to principal equipment trips, normal station shutdown, and GT operations involving fuel oil firing.

2X1 STARTUP - COLD START

2x1 Cold Start Definition: The following conditions apply concurrently (other startup cases are termed "warm" or "hot" and are defined herein):

1. The ST's HP and IP/LP rotor metal temperatures (Rotor T) are Rotor T $\leq$ 300 F.
2. The respective HRSG HP drum pressure is 185 psig or less

The two (02) 501Fs, two (02) HRSGs, and the ST/G will typically be out-of-service for 72 or more hours for these conditions to occur.

Initial Conditions:

1. All 230 kV switchyard breakers associated with the generators are open.
2. Gas turbines (GTs) and steam turbine (ST) are on turning gear.
3. Fill HRSGs with condensate and feedwater to startup levels. (See HRSG O&M Manual)
4. Align all steam cycle valves to pre-start positions. The HP, IP, and LP steam isolation valves at each HRSG shall be in the open position.. All HP, reheat, and low pressure steam vents and drains are wide open, including HRSG-supplied steam vents and drains. High point vents are open
   a. The following steam bypass valves are closed and in "HRSG out of service" mode control:
      - HP steam bypass valves to CRH.
      - HRH steam bypass valves to condenser
      - LP steam bypass valves to condenser .
   b. Each HRSG's IP letdown valve to CRH line is opened.
   c. The ST's throttle valve (TV), governor valve (GV), reheat stop valve (RSV), reheat interceptor valve (IV), LP induction stop valve (ISV), and LP induction control valve (ICV) are closed.
   d. All ST casing drains and loop drains are wide open.
   e. The HP turbine element exhaust vent to condenser valve (hereafter referred to "HP-to-condenser vent valve") is open.
   f. HP, HRH and LP Header stop valves are open.

Procedure:

1. GT #1: Start GT starting motor (2-speed motor) and run motor at speed and duration required for purging of HRSG as defined in TXP logic (based on NFPA 85 requirements). After purging, fire GT, synchronize GT to minimum load (5 to 10%), and maintain minimum load as required to stay within allowable drum ramp rate limits specified by HRSG manufacturer. Follow Vogt HP drum temperature ramp rate guidelines to 800 psig and hold for drum heat soak. During the HP drum temperature ramp of 15 degrees F per minute to 800 psig, increase GT load to 25% at a ramp rate that follows Vogt HP drum pressure ramp rate guidelines.

2. HRSG #1: Evaporation will begin to take place and pressure will begin to build in the HP, IP and LP drums and consequently in the HP, IP and LP steam lines. The HP, IP, LP and HRH (reheater outlet) superheater startup vents will be open to vent steam and any air to atmosphere. The CRH header, HRH header and HRSG reheater are initially pressurized with HRSG IP steam. Drain lines in the HRSG and BOP steam piping are open to drain condensation from the steam piping during warm up. HP, HRH, and LP vents are modulating vents to regulate pressure ramp rates, the IP vent is non-modulating and is closed at 10 psig at IP superheater outlet. The HP drum ramp rate is 15 °F per minute up to the soak pressure of 800 psig.

3. To reduce IP drum swell, the IP to CRH control valve should be kept nominally at 15% open until the IP drum pressure reaches 200 psig, and then modulates to maintain that pressure. The HRH startup vent modulates to a setpoint of 50 psig in the CRH header
4. The three different categories of steam drains are operated in the following manner:

- HRSG drains (supply by VNI) are manually closed in accordance with VNI recommendations of establishing 50 psig in the HP, IP & LP drums.
- BOP steam piping drains (supply and control by OCI) are of two different types. HP and HRH line drains are closed automatically by the DCS upon establishment of 36 degrees F superheat in the drain pot. Thermocouples in the drain pots are used to determine the amount of superheat. CRH and LP line drains have float level switches and open upon detection of *water*
- All Steam turbine cylinder and pipe drains (supply and control by SWPC) are closed as a function of ST load. ST drains upstream of the IV inlet are closed at 10% ST load, *including HP turbine and HP governor valve drain valves*. Drain valves downstream of the IV inlet are closed at 20% ST load.

5. The HRSG high point vents (not startup vents) are manually closed in accordance with HRSG recommendations, which are a drum pressure of 25 psig for the HP and 5 psig for the IP and LP.

6. The HP letdown valve to the auxiliary steam system (SJAE and gland steam system) is opened automatically on startup. This will initiate warming of the piping to these steam users. The hogger and holding ejector isolation valves are opened to admit steam, but the air side isolation valves for the hogger and holding ejectors remain closed. Once the HP steam header pressure has reached approximately 100 psig and 10 °F superheat, the gland steam system is put into operation. Once gland steam pressure (3 psig operating) is established on the ST, the hogger air side isolation valve is opened to establish vacuum. The gland steam attemperator will control to 400 °F on a cold start. The steam flow required for the hogging ejector is estimated at 8000 lb/h based on 100 psig / 442 °F motive steam. The steam flow required for the holding ejectors is estimated at 1950 lb/h based on 100 psig / 442 °F motive steam. The steam flow requirements for the ST gland steam system are lb/hr at the same steam conditions.

7. After the hogging ejector is placed in service and the ST gland steam system is operational the condenser should be "available" in approximately 20 minutes. The condenser is considered "available" when the condenser pressure is 20 inches HgA maximum, at least one circulating water pump is operating, and at least one condensate pump is operating. The remaining circulating pump and condensate pumps will be placed into service in accordance with TXP control logic during the station startup process The condenser hotwell sparging steam system is automatically in service at plant loads less than 40%.

8. Before the condenser is available, the HP startup vent on the HRSG modulates to control pressure to meet the 15 °F per minute ramp rate. Once the condenser is available, the steam turbine bypass system can be placed into service. The HP bypass operates only on the HP pressure control curve, which has a minimum setpoint of 800 psig. The vent valve will continue to ramp pressure up to 800 psig, and the HP bypass valve will remain closed even after the condenser is available. Once the 800 psig is reached, the operator closes the startup vent, and the bypass valve opens to modulate pressure. The HP startup vent must be sized to handle 800 psig at 25% GT load for the HP drum soak.

9. There is no ramp rate requirement for the IP and LP drums. The HRH vent controls pressure to 50 psig and the LP startup vent operates off the LP pressure control curve. After the condenser is available, the operator closes the HRH and LP startup vents. The HRH to condenser bypass valve opens and controls CRH system pressure to 150 psig <u>HRH bypass</u> pressure control curve per the control curve. Similarly, shutting the LP startup vent causes the LP bypass valve to open, and controls pressure to 50 psig per the curve <u>LP bypass</u> pressure control curve.

10. GT#2 can be started in the same manner as GT#1 (the starting motor for GT#1 must be off-line as a prerequisite).

11. HRSG #2 follows similar procedure.

12. As the HRSG warms up, any partial bypass of HRSG economizers to prevent steaming will be handled automatically with the economizer bypass controls. (If less than 5 °F difference between economizer outlet and drum saturation temp, non-modulating bypass valve opens) (valve is controlled with a deadband opens at 5 degrees and closing at 10 degrees)

13. Steam pressure continues to build in the HP, IP, CRH, HRH and LP steam lines while passing steam to the condenser via the bypass system and any condensed water through drains.

14. The HP bypass valve's desuperheater will control the CRH header steam temperature to approximately 600 F.

    DCS Issues:

    - When the HP bypass valve is initially opened, (>2%) the output to the spray valve is increased in three ways.
        1. Feed forward based on calculation for required spray flow.
        2. Initial boost to output on increase in spray flow required (see logic)
        3. Increase in PID output due to jump in error to the controller.

      It should be verified that this configuration will not cause overspray of the bypass steam when the bypass valve initially opens.
    - The bypass spray valve is opened to 10% position when the bypass pressure is greater than the bypass setpoint. Consider removing this logic because if the bypass valve does not open (possibly in manual) the spray will be present when there is no bypass steam. This loop already includes positioning of the spray valve on initial opening of the bypass valve as described in the bullet above.
    - The steam flow used for calculation of the "required spray flow" calculation uses HP steam flow only and no consideration is given to steam flowing to the ST. Is it possible to use a function of ST first stage pressure to approximate HP element steam flow and adjust the bypass steam flow accordingly. (note that a step change in ST load will cause the spray control feed forward to react in the wrong direction.
    - Control for the HP bypass loop utilizes the common header temperature after mixing of the bypass steam with the CRH steam. Bypass valve discharge temperature must be utilized.

15. The HRH bypass valve's desuperheater will control the downstream header steam temperature to approximately 400F. (Note that 403 F correlates with 110 psig backpressure and 1225 Btu/lb enthalpy). (Actually controlled at 50 °F superheat with +/- 10 °F operator bias capability.)

    DCS Issues:

    - Same as first two bullets of 14 above.
    - Steam flow used for the "required spray flow" calculation uses HP steam flow plus IP steam flow. Should the HP bypass spray flow and HRH attemperator flow also be considered?

16. The LP bypass valve's desuperheater will control the downstream steam temperature to approximately 375 F. (Note that 375 F correlates to 20 psig backpressure and 1225 Btu/lb enthalpy).

    DCS Issues:

- Same as first two bullets of 14 above.

17. HP drum thermal stabilization (soaking) is required to allow the drum shell temperatures to equalize. During this soak period:
    a. The HP drum pressure is maintained at 800 psig. The minimum soaking time for the HP drum is 30 minutes (This is a manual watch and not in TXP auto control) for a cold start (20 minutes for a warm start).
    b. There are no drum thermal soaking requirements for the IP and the LP drums.

18. This drum-soaking period typically occurs at the hold point when the ST is rolled.

Rolling the ST to Synchronous Speed:

19. Initial conditions:
    a. Both GTs are operating at approximately 25 % load.
    b. The high-side switchyard breaker associated with the STG is open.
    c. The HRH inlet pressure and temperature conditions, throttle inlet pressure and temperature conditions, and the condenser pressure versus HRH inlet temperature correlation shall be followed in accordance with the ST Instruction Book.
    d. The ST is latched and or on turning gear (i.e. motive power to all ST valves as per IB's.)
    e. The GV and RSV go wide open when the turbine is latched.
    f. The TV, IV, LP ISV, and LP ICV valves are closed.
    g. The TXP system is in Auto mode as per the ST IB.
    h. The HP bypass valves, HRH bypass valves, and LP bypass valves are modulated to maintain setpoints per the pressure control curves.

IV Speed Control (0 to 3160 rpm)

20. Operator enters a ST target speed of 590 rpm and ramp rate (as defined in ST IB), which corresponds to the steam turbine's supervisory instrument speed checkpoint.

21. The IV begins to open and admit steam to the IP/LP turbine. The IV is modulating the turbine speed to 590 rpm.

22. During this time the HP turbine is vented to the condenser (via the HP-to-condenser vent valve) and will be spinning in a vacuum. If the HP turbine exhaust temperature exceeds 760 F due to excessive windage heating, an operator alarm is sounded. If the HP turbine exhaust temperature exceeds 800 F due to excessive windage heating, then the steam turbine is tripped.

23. The HP bypass valves, HRH bypass valves, and LP bypass valves will continue to modulate to maintain their pressures per the control curves.

24. Steam turbine supervisory instrumentation (TSI) checks are manually performed at the 590 rpm hold point.

25. After the TSI checks have been met, the operator can now enter the next turbine speed target, which is 3450 rpm, which is also known as the "1st Speed Point". The TXP system will respond by opening the IV further until the new speed target is attained at approximately 100 to 200 rpm/minute ramp .

26. The IV controls the speed of the steam turbine from 0 to about 3450 rpm.

27. The exhaust hood spray cooling systems will be operated spraying from 2600 rpm to 10% load. The L-OC cooling system will be available for 90 sec. test sprays above 3550 rpm and automatic spray only above 3700 rpm, (overspeed events).

28. IV control of turbine speed is typically transferred to the TV at about 3450 rpm (+/- 10 rpm).

TV Speed Control (3160 to 3500 rpm)

29. At the 3450 rpm speed point the TXP requires approximately four minutes to memorize the "1st Speed Point". The IV will lock in a fixed, pressure-compensated position after timer expires (i.e., the IV will modulate in proportion to reheat pressure fluctuations).

30. The HP bypass valves, HRH bypass valves, and LP bypass valves continue to modulate to maintain their pressures per the control curves.

31. After the DEH system has memorized the IV position, the operator can now enter the next turbine speed target, 3550 rpm, at approximately 50 or 100 rpm/minute ramp rate. The TXP system will respond by opening the TV to allow steam flow through the HP turbine and exhaust to the condenser via the HP-to-condenser vent valve.

32. The TV now controls turbine speed between 3450 and 3550 rpm. The IV remains in its locked, pressure-compensated "1st Speed Point" position.

33. TV control of turbine speed is transferred to the GV at 3550 rpm.

GV Speed Control (3500 to 3600 rpm) & Synchronization

34. When the turbine reaches 3550 rpm speed, a hold point is maintained for a period of time to meet throttle and reheat inlet valve warming criteria. See the ST Instruction Book for further details.

35. After meeting the inlet valve warming criteria and with the turbine operating at the TV/GV transfer speed of 3550 rpm, the operator can perform the "TV to GV transfer" of turbine speed control. The GV is ramped closed until the TXP system senses a 30 rpm drop in speed, indicating that the GV is affecting steam flow and therefore turbine speed. When this transfer is accomplished, the TV is ramped opened to its VWO position.

36. NOTE: With the turbine now under GV speed control, the turbine speed can be controlled anywhere between 3550 rpm and synchronous speed using the GV. If the turbine's speed is reduced lower than 3500 rpm, then the intercept valve starts to close. Operator closes field breaker from the DCS screen, and synchronizer is placed in automatic.

36A. A ST ramp rate of 50 rpm per minute is entered at 3550 rpm point.

37. At 3600 rpm the STG is synchronized.

38. When the STG breaker is closed upon synchronization, the HP-to-condenser vent valve is automatically closed. The HP exhaust is then returned to the HRSG reheaters via the CRH lines.

39. If both GTs are within a required dead band of 50 MW and steam conditions of each system meet ST admission requirements (see ST IB) as well as a temperature differential no greater than 100 deg. F for HP and 50 deg. F for HRH steam at the time the STG breaker is closed , then both HRSG HP and HRH systems are automatically placed into service by switching the HP bypass valves' and the HRH bypass valves' control modes from "bypass" to "HRSG in service". These valves pressure set points are increased, which results in closing the valves. The valve(s) will re-open automatically if the steam pressure, which the valve is monitoring, begins to exceed the new "HRSG in service" pressure setting. In this way the valve(s) will attempt to modulate and to maintain the pressure being monitored.

40. When the STG breaker is closed and the GTGs power output are outside the dead band of 50 MW, then the HP & HRH system of the HRSG with the higher GTG load will automatically be placed into service by switching the HP bypass valve's and the HRH bypass valve's control modes from "bypass" to "HRSG in service". The other HRSG HP & HRH system will be placed into service manually by the operator based on system permissives that must be met (see 1x1 to 2x1 transition section below).

Speed control to load control

41. When the STG breaker is closed, the TXP system will also automatically transfer from speed control to load control by positioning the GV and IV to a position sufficient to produce minimum ST load (approximately 10%).

42. The ST will remain at the minimum load point for approximately 10 minutes to allow both the HP and the IP/LP turbines to thermally stabilize (soak). See ST Instruction Book for further detail.

Loading the GTGs and STGs:

NOTE: The STG is allowed to ramp operator-initiated STG load set-point(s) independently of the GTGs and vice versa. (Typical operation will be with the ST in sliding pressure / minimum pressure limit control operation following the CTG load as required.).

43. The operator will be able to select a GT load (up to base load) and a GT load ramp rate for both GTs in accordance with HRSG HP drum ramp rate requirements_(e.g., HP drum ramp of 50 psig per minute). Both GTs should be loaded equally from 25% load to base load.

44. Not used.

45. The HRSG HP superheater and reheater attemperators will maintain ST throttle and HRH inlet temperature limits, to the extent possible. Beyond attemperator capability, GT load must be limited to maintain ST inlet temperature limits.

46. For "steam turbine following" operation, the ST megawatt load should be set higher than the minimum output that allows the ST to operate in sliding pressure operation. This is the normal mode of operation.

Alternatively, the operator will be able to select a ST load (up to base load) and a ST load ramp rate in accordance with the STIB requirements. The GV and IV will both ramp open proportionally to increase STG load until the ST load reaches 100%.

47. The LP induction line will be placed into "LP Induction in service" mode when the following conditions are met:
    a. The steam turbine is at 20% load (38MW) or greater.
    b. The HP and HRH systems are operating in "HRSG in service" mode.
    c. The LP induction steam meets the ST's criteria for minimum superheat and temperature differential before being placed into service. Refer to ST Instruction Book.
48. The LP bypass valves' control mode is switched to "LP Induction in service" and the valves' pressure setpoint is raised (closing the valve). The ISV and ICV valves are opened, diverting LP steam flow to the LP section of the ST.

49. When operating in "HRSG in service" control, the HP bypass valves', the HRH bypass valves', and the LP bypass valves' pressure set-points are set above the expected system operating pressures (See bypass control curves).

50. As a protection to HRSG drum steam quality, when a minimum pressure versus steam flow operating curve is required, the following system valves will be used to control said pressure [with the bypass valves closed] for given function:

HP drum pressure	GV	(HP carryover curve – VNI)
IP drum pressure	IP to CRH letdown valve	(220 psig at HRH to ST [max])
LP drum pressure	LP ICV.	(LP carryover curve – VNI)

51. For 2 x 1 operation, the HRH and CRH circuits will be in sliding pressure operation at all times. For 1 x 1 operation, the operating pressure will be limited to approximately 65% of base load 2 x 1 operating pressure

52. The auxiliary steam must be available at the gland steam supply skid at all times.

53. For ST cold start, the steam supply to the holding ejectors is switched from the HP header to the CRH header when the CRH header pressure at the SJAE CRH takeoff is sufficient to supply 110 psig motive steam at the SJAE inlet flange. The motive steam supply must be conditioned to the 110 psig/442 F state-point condition, as previously supplied by the HP header. To provide superheated steam to the gland steam system for ST Hot and Warm start the HP supply to the auxiliary steam header must be in service.

54. The plant is now in 2x1 base load operation, with GTs at base load and the ST at VWO.

55. Notes:
    a. If the operator places the STG at some load setting less than its 100% load and the GTGs are placed in GT loads which could result in steam pressures that increase above the bypass valves' "HRSG in service" pressure settings, then the bypass valve(s) will open to maintain their respective "HRSG in service" pressure settings. This arrangement is instrumental to preventing the GTG(s) from tripping off-line due to steam pressures approaching the drum pressure relief valve settings (see GTG trips section below). Thus, the "HRSG in service" pressure control curves for these valves establish a maximum operating pressure boundary for given steam production during the overall plant operation.
    b. If system pressures exceed the "HRSG in service" pressure control curve set-points and reach the superheater pressure relief valve setpoints, the GT will run back to reduce the system pressure

reseating the relief valve. If the system pressure is not reduced by GT runback and the relief valves continue to relieve system pressure, the GT will be tripped.

c. The HP drum pressure will be maintained at a pressure that results in a 600 F exhaust gas temperature (minimum) entering the SCR system. This pressure control will be accomplished by the GV.
d. For ST protection, on high temperature alarm and on reduction of ST load from 10% load to 400 rpm, the exhaust hood spray cooling systems will automatically actuate.
e. In a 2 x 1 configuration, mass flow control to each HRSG reheater is passive.
f. If there is an HP or HRH header temperature differential that exceeds 100 F during 2x1 operation, then one of the HRSGs must be taken out-of-service.
g. If there is an LP header temperature differential that exceeds 50 F during 2x1 operation, then one of the HRSG LP systems must be taken out-of-service.
h. If there is a HP or HRH header temperature differential that exceeds 200 F during 2x1 operation, then one of the HRSGs must be taken out-of-service.
i. If there is a LP header temperature differential that exceeds 50 F during 2x1 operation, then one of the HRSG's LP systems must be taken out-of-service.
j. Catch problem with load adjustments. If it doesn't work, place HRSG (offending) in "HRSG out-of-service" to go to bypass mode, and ultimately trip if problem doesn't go away.

2X1 STARTUP - WARM START

1. 2x1 Warm Start Definition: The following conditions apply concurrently: The St's HP and IP/LP rotor metal temperatures (Rotor T) are 300 F < Rotor T $\leq$ 800 F. This is measured at the HP first stage blade ring and displayed on the TXP screen graphic..
2. The HRSG HP drum pressures are between a cold pressure of 185 psig and a hot pressure of less than 835 psig.

Two 501Fs, two HRSGs, and the STG will typically be out-of-service for more than 8 hours but less than 72 hours.

Procedure:
The procedure is the same as 2x1 Cold Start, except for the following:

1. No HRSG high point venting for system air removal is required.

2. Modulation of HRSG superheater startup vents as required to limit 15 F/min. ramp to HP drum soak pressure of 800 psig.

3. No GT hold is required at 25% load. Ramp GTs to meet the HRSG HP drum ramp and to meet the ST inlet steam requirements. HP drum ramp rate is 15 F/minute after the 15. minute soak time at 800 psig. The IP and LP drums have no ramping restrictions.

4. HRSG drain valves should be opened to blow out any condensed steam.

5. (Not used)

6. Steam conditions required at ST for rolling the ST will consist of a higher steam temperature than that required for a ST cold start. The higher steam temperature requirements for ST roll will result in a higher GT load. Steam conditions must be in accordance with STIB requirements.

7. ST roll & soak times are reduced in accordance with STIB requirements.

2X1 STARTUP – HOT START

2x1 Hot Start Definition: The following conditions apply concurrently:

1. The ST's HP and IP/LP rotor metal temperatures (Rotor T) are Rotor T > 800 F.
2. The HRSG HP drum pressures are greater than 850 psig. (VNI startup procedure)
3. HP drum ramp rate is 50 psig/min

Two 501Fs, two HRSGs, and the STG will typically be out-of-service for less than 8 hours.

Procedure:

1. The procedure is the same as 2x1 Cold Start, except for the following:
2. No HRSG high point venting for system air removal is required.
3. No Modulation of HRSG superheater startup vents is required.
4. No GT hold is required at 25% load. Ramp GTs to meet the HRSG HP drum ramp rate and soak pressure requirements and to meet the ST inlet steam requirements.
5. HRSG soak times are eliminated
6. HRSG drain valves should be opened to blow out any condensed steam.
7. Steam conditions required at ST for rolling the ST will consist of a higher steam temperature than that required for a ST cold start. The higher steam temperature requirements will result in a higher GT load at ST roll. Steam conditions must be in accordance with ST IB requirements.
8. ST roll & soak times are reduced in accordance with ST IB requirements.
9. HP drum ramp rate is 50 psig/min. The IP and LP drums have no ramping restrictions.

1X1 STARTUP – COLD START

1. Definitions and procedure are same as 2x1 Cold Start, except that the GT/HRSG that is not in service is isolated in the following systems: HRH steam, HP steam, CRH steam, LP steam, and the LP Economizer.
2. The operating system pressures in 1x1 operation may be based on predetermined minimum pressures versus steam flow. With the bypass valves and IP letdown valve in "HRSG in service" operation, these minimum pressures will be controlled via throttling the GV, IV, IP letdown valve, and LP ICV. At this time it is undetermined if these 1x1 minimum operating pressure curves will be identical to the 2x1 minimum operating pressure curves. HP: 1x1 pressure similar to 2x1. Reheat: 1x1 approximately 65% of 2x1 pressure at base load.

1X1 STARTUP – WARM START

1. Definitions and procedure are same as 2x1 Warm Start, except that the GT/HRSG that is not in service is isolated in the following systems: HRH steam, HP steam, CRH steam, LP steam, and the LP Economizer.

2. The operating system pressures in 1x1 operation may be based on predetermined minimum pressures versus steam flow. With the bypass valves and IP letdown valve in "HRSG in service" operation, these minimum pressures will be controlled via throttling the GV, IV, IP letdown valve, and LP ICV. At this time it is undetermined if these 1x1 minimum operating pressure curves will be identical to the 2x1 minimum operating pressure curves. HP: 1x1 pressure similar to 2x1. Reheat: 1x1 approximately 65% of 2x1 pressure at base load.

1X1 STARTUP – HOT START

1. Definitions and procedure are same as 2x1 Hot Start, except that the GTG/HRSG that is not in service is isolated in the following systems: HRH steam, HP steam, CRH steam, LP steam, and the LP Economizer.

2. The operating system pressures in 1x1 operation may be based on predetermined minimum pressures versus steam flow. With the bypass valves and IP letdown valve in "HRSG in service" operation, these minimum pressures will be controlled via throttling the GV, IV, IP letdown valve, and LP ICV. At this time it is undetermined if these 1x1 minimum operating pressure curves will be identical to the 2x1 minimum operating pressure curves. HP: 1x1 pressure similar to 2x1. Reheat: 1x1 approximately 65% of 2x1 pressure at base load.

2A. For general guidance:
- Normal vacuum for 2 X 1 = 2 inches Hg
- ST trips when vacuum goes down to 7 to 8 inches of water

TRANSITIONING FROM 1X1 TO 2X1

Initial Conditions:

1. One GTG, one HRSG, and the STG are in service. This first GTG is operating at some GT load.

2. Initial conditions/alignments of 2x1 startup are applicable to second GTG & HRSG that are initially out-of-service only.

Procedure:

1. The second GTG and HRSG that is initially out-of-service is warmed up, vented, and soaked in similar fashion as a 2x1 startup.

2. The second HP, HRH, and LP systems are in "HRSG out of service" mode of operation.

3. Required permissives are mandatory prior to the operator manually placing the second HP and HRH systems into service. These permissives include:
   a. The two GTG loads are within a 50 MW dead band. (Load mismatch can increase after both steam trains are in service.)
   b. Not used.

c. HP temperatures from CT/HRSG train 1 and 2 are within a 100 F temperature differential. HRH temperatures from CT/HRSG train 1 and 2 are within 50 F temperature differential

4. The three motor operated steam isolation valves, HP, CRH and HRH, are opened simultaneously from the DCS.

5. HP and HRH bypass valves control mode is switched to "HRSG in service". The valves' pressure set points are increased resulting in closing the valves.

6. The operator will be able to select a ST load (up to base load) and a ST load ramp rate in accordance with the ST IB requirements. The GV and IV will both ramp open proportionally (to avoid thrust imbalance) to increase STG load until the ST load reaches operator setpoint.
   a.

7. Required permissives are mandatory prior to the operator manually placing the second LP system into service. These permissives include:
   a. LP header temperatures from CT/HRSG train 1 and train 2 are within a 50 F temperature differential

8. The LP bypass valves' control mode is switched to "HRSG in service" and the valves' pressure set point is raised (closing the valve). The ISV and ICV valves open, diverting LP steam flow to the LP section of the ST.

GTG TRIPS

<u>For trip logic, see SWPC training documentation and TXP SAMA logics.</u>

There are two possible scenarios:

Scenario 1: Steam Turbine Trip Imminent, 1x1 operation and GT trips, or 2x1 operation and both GTs and GT breakers trip simultaneously

Initial Conditions:
1. One or both GT/HRSG trains are in service, ST is in service.

2. Steam turbine bypass valves are in "HRSG in service" mode, but they may or may not be open, depending on GT load and ST load.

Procedure:
1. An unplanned trip of operating GT in 1x1 operation, unplanned trip of both GTs in 2x1 operation, or operator-initiated stop of one or both GTs, causes an immediate trip of the ST.

2. Upon trip of the ST and ST switchyard breaker opening, the bypass system switches from "HRSG in service" mode to "HRSG out of service" mode, reducing the pressure control setpoints, and the bypass valves control steam pressures per the pressure control-curves.

Scenario 2: Steam Turbine Remains in Service, 2x1 operation and one GT and GT switchyard **breaker trips**

Initial Conditions:
1. **Both GT/HRSG trains are in service, ST is in service.**

2. **Steam turbine bypass valves are in "HRSG in service" mode, but they may or may not be open, depending on GT load and ST load.**

Procedure:

1. **Upon trip of one operating GT and the GT switchyard breaker opening, the HP, HRH, and LP steam isolation valves on the corresponding GT/HRSG train close.**

2. **The HP, HRH and LP Bypass valves of the corresponding GT/HRSG train go into "HRSG out of service" mode, to maintain the system pressures below the relief valve setpoints and modulate to pressure control curves**

3. **The ST GV and IV pressure control setpoints change to 1x1 operation pressure setpoints.**

4. **The LP Induction control valve maintains LP system pressure per the pressure setpoint.**

STG TRIPS

There is one possible scenario for a ST trip.

Scenario 1: 1x1 operation and ST trips, 2x1 operation and ST trips

Initial Conditions:

1. One or both GT/HRSG trains are in service, ST is in service.

2. **Steam turbine bypass valves are in "HRSG in service" mode, but they may or may not be open, depending on GT load and ST load.**

Procedure:

1. **Upon trip of the ST and the ST generator breaker opening, the HP, HRH, and LP steam isolation valves for each GT/HRSG train close.**

2. **The HP, HRH and LP Bypass valves of each GT/HRSG train go into "HRSG out of service" mode,** reducing the pressure control setpoints, and the bypass valves control steam pressures per the pressure control curves/setpoints.

HRSG TRIPS

1. Every HRSG induced trip will result in an immediate trip of the corresponding GT.

2. The associated main steam isolating valves in the steam systems (HP/HRH/CRH/LP) will close to isolate this HRSG from the operating HRSG.

RESTARTs

Scenario 1: Steam Turbine Hot Restart after a trip from 2 x 1 operation

Initial Conditions:
1. GT1 and GT2 are at base load. ST Bypass Valves are operating in "HRSG out of service" mode.

Procedure:
1. The procedure is the same as the ST startup procedure found in the 2x1 Hot Start Procedure, except for the following:

    1.1. GT load must be ramped down to meet the required ST startup inlet steam pressure and temperature range per STIB.

2.

Scenario 2: Steam Turbine Hot Restart in 1 x 1 operation

Initial Conditions:
1. GT1/HRSG1 or GT2/HRSG2 is at base load. The ST Bypass Valves are operating in "HRSG out of service" mode. The other GT/HRSG train is out of service and isolated from the operating train.

Procedure:
1. The procedure is the same as the ST startup procedure found in the 1x1 Hot Start Procedure, except for the following:

    1.1. GT load must be ramped down to meet the required ST startup inlet steam pressure and temperature range per STIB.

Scenario 3: Gas Turbine Restart with Hot HRSG and part loaded ST after 1 GT trip from 2x1 operation

Initial Conditions:
1. GT1/HRSG1 or GT2/HRSG2 are at base load. The ST is operating at part load. The ST Bypass Valves for the operating GT/HRSG train are operating in "HRSG in service" mode. The tripped GT/HRSG train is isolated from the operating train. The ST Bypass Valves for the tripped HRSG train are operating in "HRSG out of service" mode and, if necessary, will actuate to lower the system pressure of the tripped CT/HRSG train. Non running GT is on turning gear.

Procedure:
1. The procedure for starting the GT/HRSG train that is out of service is the same as the GT/HRSG startup procedure found in the 2x1 Hot Start Procedure except for the following:

    1.1. The ST startup procedure discussed in the 2x1 Hot Start Procedure is not applicable. Instead follow the procedure for admitting steam to the ST found in the procedure for Transitioning from 1x1 Operation to 2x1 Operation.

Scenario 4: Gas Turbine Restart with Hot HRSG and ST after trip from 1x1 operation

Initial Conditions:
1. GT and ST are on turning gear.

Procedure:
1. The procedure is the same as the 1x1 Hot Start Procedure.

2X0 OPERATION, 100% ST BYPASS

The procedure is the same as the 2x1 Cold Startup Procedure, except for the following:

1. **The ST startup procedure is not required.**

2. **The bypass valves remain in "HRSG out of service" mode.**

3. **The steam system isolation valves are open permitting flow to the steam jet air ejectors and gland steam system.**

1X0 OPERATION, 100% ST BYPASS

The procedure is the same as the 1x1 Cold Startup Procedure, except for the following:

1. **The ST startup procedure is not required.**

2. **The bypass valves remain in "HRSG out of service" mode.**

3. **The steam system isolation valves for the CT/HRSG train that is out of service are closed.**

STATION SHUTDOWN

Initial Conditions:
1. **2x1 or 1x1 station operation**

Procedure:
1. **The operator will select GT Normal Stop.**

2. **The ST will remain in VWO operation and the ST load will decrease due to the decreased steam production. At some point in the shutdown the ST intercept and governor valves will throttle to maintain system pressures per the pressure control curves.**

3. **Operator will manually trip the ST at some minimum load, approximately 10%.**

4. **The ST will automatically go onto turning gear once a zero speed is sensed. The operator will visually verify that turning gear is engaged and operation initiated.**

5. **Operator will manually trip the GT at some minimum load, approximately 10%.**

FUEL GAS PREHEATER OPERATION

Initial Condition:

1. High-side switchyard breaker associated with operating GT is closed and GT is operating at desired setpoint via gas supplied directly to the GT.

2. Preheater associated with each GT is initially bypassed.

Operation:

1. The operator releases the gas side inlet, outlet and bypass valves to operate.

2. The operator releases the water side temperature control valve to operate controlling the condensate preheater inlet temperature to approximately 52°C (125°F).

3. IP feedwater is taken off an intermediate pressure takeoff of the boiler feedwater pump, routed through the natural gas fuel preheater and discharged into the condensate header.

FUEL OIL OPERATION

During fuel oil service, the operation of the cold end of the HRSG is modified to avoid corrosion on the flue gas side of the HRSG due to the sulfuric acid dew point.

This modification is accomplished by bypassing the condensate flow downstream of the fuel gas preheater condensate line around the condensate preheater to a point upstream of the LP feedwater control valve. This puts condensate flow directly into the LP drum, where the incoming water is heated up to saturation conditions.

If the LP drum pressure falls below 15 psig, steam from the IP drum will be pegged into the LP drum raising the LP drum pressure.

DOCUMENT III. J. 11.

ALTERNATE METHODS
OF OPERATION

ALTERNATE METHODS OF OPERATION

Combustion Turbine Generators CTG1 and CTG2

Method No.	Equipment	Fuel Type	Heat Input Range (MMBtu/hr)	Maximum Operating Hours (Per CTG)		
				(Hrs/Day)	(Days/Wk)	(Hrs/Yr)
1	CTG1 & CTG2	Natural Gas	0 — 1,962	24	7	8,760
2	CTG1 & CTG2	No. 2 Oil	0 — 1,888	24	7	See Note 2

Notes:

1. Top of heat input range represents 100% load and 32°F ambient air temperature operating conditions.
2. No. 2 fuel oil consumption for both CTGs combined is limited to 41,751,000 gallons per year.

DOCUMENT III. J. 15.

ACID RAIN PART – PHASE II

RECEIVED 2000

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

June 27, 2000

Mr. Michael P. Opalinski
Designated Representative
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
P.O. Box 272000
Tampa, Florida 33688-2000

Dear Mr. Opalinski:

Re: Acid Rain Phase II Permit Application Form for the Payne Creek Generating Station

Thank you for submitting the referenced form and the corresponding Certificate of Representation for this facility. We have reviewed these materials and deem your application complete. If you have any questions, please contact Tom Cascio at 850/921-9526.

Sincerely,

Scott M. Sheplak

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

cc: Jenny Jachim, U.S.EPA, Region 4

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

VIA FEDERAL EXPRESS

June 13, 2000

Mr. Scott Sheplak
Florida Department of Environmental Protection
Division of Air Resources Management, MS 5500
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Sheplak:

Attached please find a completed Phase II Permit Application and four copies for Seminole Electric Cooperative, Inc.'s Payne Creek Generating Station. This combined cycle facility located in Hardee County, Florida began construction in March of this year and is scheduled for commercial operation on January 1, 2002. The Payne Creek Generating Station consists of two (2) combustion turbines whose waste heat is connected to individual heat recovery steam generators whose steam is then connected to a single steam turbine. For this reason, we have designated each combustion turbine as boiler 1A and 1B respectively.

If you have any questions or require any additional information, please contact me or Mike Roddy at (813) 963-0994.

Sincerely yours,

M.P. Opalinski

Michael P. Opalinski
Designated Representative

bcc: J. Duren
J. Welborn
J. Pittman
M. Roddy

Phase II Permit 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	State	ORIS Code
Payne Creek Generation Station,	FL	

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

a Boiler ID#	Compliance Plan b Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	c Repowering Plan	d New Units Commence Operation Date	e New Units Monitor Certification Deadline
1A	Yes	No	Jan. 1, 2002	March 1, 2002
1B	Yes	No	Jan. 1, 2002	March 1, 2002
	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 will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

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

Permit 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, 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 permitting authority determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain permit;
(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 permitting authority; 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 permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 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 Administrator or permitting authority:
(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 th source beyond such 5-year period until such documents are superseded because of the submission of a new

Plant Name (from Step 1)

Recordkeeping and Reporting Requirements (cont)

certificate of representation changing the designated representative;

(ii) All emissions monitoring information, in accordance with 40 CFR part 75;

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under th Acid Rain Program; and,

(iv) Copies of all documents used to complete an Acid Rain part application and any other submission under the Aci 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 4(CFR part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain par application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8, 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 Rair 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 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, 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 a written exemption under 40 CFR 72.7 or 72.8 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 Michael P. Opalinski, Designated Representative

Signature *Michael P. [signature]*	Date 6/13/00

STEP 5 (optional)
Enter the source AIRS
and FINDS identification

AIRS
FINDS

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

June 23, 2000

Mr. Scott Sheplak
Florida Department of Environmental Protection
Division of Air resources Management, MS 5500
2600 Blair stone Road
Tallahassee, FL 32399-2400

Dear Mr. Sheplak:

Attached please find the Certificate of Representation for Seminole Electric Cooperative, Inc's Payne Creek Generating Station. If you have any questions please contact me at (813) 963-0994.

Sincerely,

Mike Roddy

Mike Roddy
Senior Environmental Engineer

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Certificate of Representation

For more information, see instructions and refer to 40 CFR 72.24

This submission is: [x] New [ ] Revised (revised submissions must be completed in full; see instructions)

This submission includes combustion or process sources under 40 CFR part 74 [ ]

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

Plant Name	State	ORIS Code
Payne Creek Generating Station	FL	

STEP 2
Enter requested information for the designated representative.

Name: Michael P. Opalinski

Address: Seminole Electric Cooperative, Inc.
P. O. Box 272000
Tampa, FL 33688-2000

Phone Number: (813) 963-0994 Ext. 1233

Fax Number: (813) 264-7906

E-mail address (if available): mopalinski@seminole-electric.com

STEP 3
Enter requested information for the alternate designated representative, if applicable.

Name: James R. Duren

Phone Number: (813) 963-0994 Ext. 1207

Fax Number: (813) 264-7906

E-mail address (if available): jduren@seminole-electric.com

STEP 4
Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the combustion or process source is located.

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the 'designated representative' for the affected source and each affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

> I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and
>
> Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

Payne Creek Generating Station
Plant Name (from Step 1)

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected 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.

M. P. [signature] Signature (designated representative)	Date 6/23/00
[signature] Signature (alternate designated representative)	Date 6/23/00

STEP 5
Provide the name of every owner and operator of the source and identify each affected unit (or combustion or process source) they own and/or operate.

Name: Seminole Electric Cooperative, Inc.					☒ Owner	☐ Operator
ID# 1A	ID# 1B	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

APPENDIX B

CURRENT AIR
CONSTRUCTION PERMIT

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 20, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

RECEIVED SEP 25 2001

Mr. Mike Roddy
Senior Environmental Engineer
Seminole Electric Cooperative, Inc.
Post Office Box 272000
Tampa, Florida 33688-2000

Re: DEP File No. 1050340-001-AC; PSD-FL-214B
Payne Creek Generating Station

Dear Mr. Roddy:

The Department has reviewed your request of June 5, 2001, and subsequent letter dated July 10, 2001. The request to provide relief from 40 CFR 60 Subpart GG testing and monitoring requirements as well as removing initial testing requirement for beryllium and arsenic is acceptable to the Department. The Department's acceptance of this request is based on the following:

- Environmental Protection Agency Region IV has routinely received and approved numerous requests for alternative testing and monitoring procedures under Subpart GG. These routine alternatives were recently described in a May 26, 2000 letter from Douglas Neeley to the Region IV State and Local Air Directors. The letter delegates authority to the Florida Department of Environmental Protection for approval of these alternatives. The requests from Seminole fall within the scope of issues addressed in EPA's letter.
- At the time the permit was issued (September 1995), beryllium was a pollutant subject to the Department's PSD rules. At the request of the Florida Coordinating Group, the Department in 1997-98, delisted asbestos, beryllium and vinyl chloride as PSD pollutants consistent with EPA Headquarters guidance.
- Although arsenic was not a "PSD pollutant," it was included in the permit by adherence to the procedures described in Table A-4 of the "Draft New Source Review Workshop Manual," October 1990. These procedures apply to permits issued under the authority of 40 CFR 52.21. The Department concludes that the same logic that "delisted" beryllium as a PSD pollutant would clearly apply to a pollutant that was not even listed.
- The Department reviewed documents (dated May 14 and December 30, 1999) prepared by EPA to support a possible Maximum Achievable Control Technology (MACT) for hazardous air pollutants (HAPs) from gas turbines. Arsenic emissions were not addressed in the documents (as opposed to formaldehyde, benzene, mercury and certain other organic and metal HAPs). The focus of control is on organic emissions and on catalytic oxidation systems. The Seminole project already includes an oxidation system that addresses any possible HAPs concern.

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

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
N≤0.015	0
0.015<N≤0.1	0.04(N)
0.1<N≤0.25	0.004+0.0067(N–0.1)
N>0.25	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

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 NOx 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 is 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.

(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.

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 NOx CEMS shall be used to demonstrate compliance with the NOx 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.

[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).

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

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

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

<u>Pursuant to 40 CFR 60.335 Test Methods and Procedures</u>:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent 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 (NOx) shall be computed for each run using the following equation:

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

where:

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

<u>Department requirement</u>: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected 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.

<u>Department requirement</u>: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx 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 NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

<u>Department requirement</u>: The owner or operator is allowed to make the initial compliance demonstration for NOx 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 NOx 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.

<u>Department requirement</u>: 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.

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 filing 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 must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

for ______________________
Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this permit modification was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on _____________ to the person(s) listed:

Mr. M. Roddy, SECI*
Mr. H. Oven, PPSO
Mr. B. Thomas, DEP-SWD
Mr. G. Worley, EPA
Mr. J. Bunyak, NPS

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 9/21/01
(Clerk) (Date)

FINAL DETERMINATION

Seminole Electric Cooperative, Incorporated (SECI)
Payne Creek Generating Station
DEP File No. PSD-FL-214B / 1050340-001-AC

An Intent to Issue a PSD Permit Modification for SECI, Payne Creek Generating Station, located near Bowling Green, Hardee County, Florida, was distributed on August 17, 2001. The Public Notice of Intent to Issue PSD Permit Modification was published in the Herald-Advocate on August 23, 2001. Copies of the draft permit modification were available for public inspection at the Department offices in Tampa and Tallahassee.

The Department received no comments from the public, the applicant, the EPA Region 4 office or the National Park Service.

The final action of the Department is to issue the construction permit as proposed.

RECEIVED JUL 27 1999

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT MODIFICATION

In the Matter of an
Application for Permit Modification

Mr. Michael P. Opalinski
Seminole Electric Cooperative Incorporated
Post Office Box 272000
Tampa, Florida 33688-2000

Permit: PSD-FL-214A / PA-89-25SA

Enclosed is the FINAL Permit Modification which reflects the use of SCR and oxidation catalyst control systems at the Payne Creek generating Station in Hardee County. This permit is issued pursuant to Chapter 403, Florida Statutes and 62-4 through 297, F.A.C and 40 CFR 52.21 - Prevention of Significant Deterioration(PSD).

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.

Executed in Tallahassee, Florida.

C.H. Fancy

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 7-23-99 to the person(s) listed:

Mr. Michael P. Opalinski, SECI *
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Bill Thomas, DEP SWD
Mr. Hamilton S. Oven, DEP PPS

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.

Kim Tober 7-23-99
(Clerk) (Date)

FINAL DETERMINATION

Seminole Electric Cooperative, Incorporated (SECI)
Hardee Power Station Unit 3 (Payne Creek Generating Station)
Permit No. PSD-FL-214A / PA-89-25SA

An Intent to Issue a PSD Permit Modification for SECI, Hardee Power Station Unit 3 (Payne Creek Generating Station), located near Bowling Green, Hardee County, Florida, was distributed on May 6, 1999. The Public Notice of Intent to Issue PSD Permit Modification was published in the Herald-Advocate on May 20, 1999. Copies of the draft permit modification were available for public inspection at the Department offices in Tampa and Tallahassee.

The National Park Service, the U.S. Environmental Protection Agency or the public submitted no comments. Several editorial comments on the proposed permit modification were submitted by the applicant in response to the public notice. The Department will make changes based on those comments. Additionally, the applicant wanted to change the expiration date of the permit to March 4, 2002.

A summary of the comments received and the Department's responses to those comments are provided in the following paragraphs:

Comment 1: SECI submitted a comment requesting that the word "revised" be inserted before permit in Specific Condition H.3. The change will give SECI 18 months period from the issuance of the revised permit for the initiation of BACT on the units on which construction has not commenced.

Response: The Department will incorporate the source obligation conditions from 40 CFR 52.21 (r)(2). SECI has agreed that construction (delayed since 1995) will commence by June 2000. Specific Condition H.3 will be replaced by the following:

<u>Approval to construct shall become invalid if construction is not commenced by June, 2000, if construction is discontinued for a period of 18 months or more, or if construction is not completed by March 4, 2002. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified.</u> [40 CFR 52.21(r)(2)].

Comment 2: SECI submitted comments on May 26 and June 4, 1999, requesting extension of the expiration date of the permit to March 4, 2002. During 1995, SECI received a proposal from Florida Power Corporation to supply SECI with approximately 450 MW of firm capacity for three years and 150 MW of system intermediate capacity for the period of 1999 through 2013. Through subsequent negotiations, SECI found that this arrangement would result in significant savings to its Member Systems when compared to this project, and thus decided to delay the project.

Response: The Department will set June 2000 as the date by which construction must commence, and March 4, 2002, as the "reasonable time" by which construction must be completed. The extension moots the conditions related to installation by November 1, 2000 of DLN burners capable of achieving 9-12 ppm. SECI may install either DLN or SCR systems to meet a NO_x limit of 9 ppmvd @ 15% O_2.

The final action of the Department is to issue the permit with the changes noted 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:
Seminole Electric Cooperative Incorporated
P.O. Box 272000
Tampa, FL 33688-2000

Permit Number: PSD-FL-214A/PA-89-25SA
Issued: 9/28/95 Revised: 7/21/99
County: Polk & Hardee
Latitude/Longitude: 27°38'30"N 81°57'45"W
Project: 488 MW Combined Cycle Power Plant

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-212 and 62-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and specifically described as follows:

For a 488 MW (nominal) combined cycle power plant consisting of two 157.5 MW (nominal) combustion turbines (CTs), two heat recovery steam generators (HRSGs), a 173 MW (nominal) steam turbine generator and a 4.4 million gallon fuel oil storage tank. The maximum heat input at 32°F is 1962 MMBtu/hr/CT (natural gas) and 1888 MMBtu/hr/CT (oil). The plant will be located at the Polk and Hardee County site near Bowling Green, Florida which is also the site of a 295 MW power plant which is operated by Hardee Power Partners Limited (HPPL). The combustion turbines are to be Westinghouse Model 501F (D) or equivalent and equipped with dry low NO_x combustors and a Selective Catalytic Reduction (SCR) system for natural gas firing and wet injection for fuel oil firing. The CT will be fired with natural gas and No. 2 low sulfur fuel oil with a sulfur content limit not to exceed 0.05 percent, by weight, as a back-up only. Each CT will also be equipped with a carbon monoxide oxidation catalyst control system.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Howard L. Rhodes, Director
Division of Air Resources Management

Attachments are listed below:

1. Seminole Electric Cooperative Incorporated's (SECI) application received May 9, 1994.
2. Department's letters dated June 27, September 21, and November 16, 1994.
3. SECI's letters dated August 26, October 6, and November 23, 1994.
4. SECI's letter dated February 9, 1995.
5. SECI's letters dated December 1 and December 21, 1998; January 29 and February 11, 1999.

GENERAL CONDITIONS:

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, F.S. 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.

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, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), F.S., the issuance of this permit does not convey any 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 of 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.

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.

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 F.S. and Department rules, unless specifically authorized by an order from the Department.

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.

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 any 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.

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.

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 F.S. or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.

11. This permit is transferable only upon Department approval in accordance with 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.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

(X) Determination of Best Available Control Technology (BACT)
(X) Determination of Prevention of Significant Deterioration (PSD)
(X) Compliance with New Source Performance Standards (NSPS)

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 for 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:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and,
- the results of such analyses.

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.

16. Circumvention. No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly pursuant to Rule 62-210.650 F.A.C.

SPECIFIC CONDITIONS:

The construction and operation of the project shall be in accordance with all applicable provisions of Chapters 62-210 through 62-297 and 62-4, Florida Administrative Code (F.A.C.), and 40 CFR 60, Subpart GG, Appendix A, Appendix B, and Appendix F (1994 version). The following emission limitations and conditions reflect the BACT determinations for the 315 megawatts (nominal) (MW; two 157.5 MW (nominal) combined cycle combustion turbines) of generating capacity. Each combustion turbine (CT) will be connected to a heat recovery steam generator (HRSG), which will recover the waste heat to produce steam for utilization in a single 173 MW (nominal) steam turbine. There is no fuel firing in the associated HRSG. The facility will have a total nominal generating capacity of 488 MW (nominal) In addition to the foregoing, the project shall comply with the following Specific Conditions:

A. General Requirements

1. Pursuant to Rule 62-212.200(56), F.A.C., Potential to Emit (PTE), the maximum heat input to each Westinghouse 501F (D) CT, or equivalent, at an ambient temperature of 32°F, shall neither exceed 1,962 MMBtu/hr while firing natural gas nor 1,888 MMBtu/hr while firing fuel oil.

2. Pursuant to Rule 62-212.200(56), F.A.C., PTE, the CTs may operate continuously, i.e., 8,760 hrs/year.

3. Pursuant to Rule 62-212.200(56), F.A.C., PTE, only natural gas or No. 2 fuel oil is allowed to be fired in the CTs. The maximum sulfur content limit of the No. 2 fuel oil shall not exceed 0.05 percent, by weight.

4. Pursuant to Rule 62-212.200(56), F.A.C., PTE, the maximum No. 2 fuel oil consumption allowed to be burned is 41,751,000 gallons per year, which is equivalent to 1500 hours per CT per year of operation at full load(not to exceed 3,000 hrs/yr between the two CTs). The No. 2 fuel oil is to be used as a back-up fuel only.

5. Pursuant to Rule 62-296.310(3),F.A.C., Unconfined Emissions of Particulate Matter (PM), the emissions of unconfined PM shall be minimized during the construction period by covering or watering dust generating areas.

B. Emission Limits

1. Pursuant to Rule 62-212.410, F.A.C., BACT, the maximum allowable emission limitations from two CTs, when firing natural gas or No. 2 fuel oil, shall not exceed the following:

PERMITTEE:
Seminole Electric Cooperative Inc.

Permit Number: PSD-FL-214A
(PA-89-25SA)

MAXIMUM ALLOWABLE EMISSION LIMITATIONS

POLLUTANT	FUEL	CONCENTRATION	lbs/hr(a)	TPY(b)	TPY(TOTAL)[c]
NO_x	Gas	9 ppmvd(d)	68	596	906
	Oil	42 ppmvd(e)	336	504	
CO	Gas	20 ppmvd	71	622	618
	Oil	25 ppmvd	91	136	
PM/PM_{10}	Gas		7	65	147
	Oil		67	100	
SO_2	Gas		5	47	182
	Oil		101	152	
VOC	Gas	5 ppmvd	10	88	99
	Oil	10 ppmvd	21	31	
Sulfuric Acid Mist	Gas		1	6	39
	Oil		22	34	
Beryllium	Oil		0.0049	0.007	0.007
Arsenic	Oil		0.0097	0.014	0.014
Visible Emissions	Gas		≤ 10 percent opacity		
	Oil		≤ 10 percent opacity		

(a) The emission limitations in lbs/hr/CT are a 1-hour average as determined pursuant to the Performance Testing conducted pursuant to Condition C.1 below.

(b) The annual emission limitations (TPY) for natural gas are based on two CTs operating at full load for 8,760 hours per year. The annual emission limitations (TPY) for fuel oil are based on the equivalent of full-load operation for a maximum of 1500 hours per year for each of the two CTs (not to exceed 3,000 hrs/yr between the two CTs). The emission calculations are also based at a worst case ambient temperature of 32°F.

(c) Maximum allowable emissions from two CTs if any fuel oil is burned at the facility during the year. The emission calculations are also based at an ambient temperature of 59°F.

(d) The natural gas NO_x allowable emission limitation of 9 ppmvd is corrected to 15 percent O_2. An interim limit of 12 ppmvd (91 lb/hr/CT, 797 TPY)corrected to 15 percent O_2 shall be allowed for a period of one year from the startup date. Compliance shall be determined through the initial and annual compliance tests.

(e) The fuel oil NO_x allowable emission limitation of 42 ppmvd is corrected to 15 percent oxygen. Compliance shall be determined through the initial and annual compliance tests. The annual compliance test will be required if the fuel oil is fired for more than 400 hours in the preceding 12-months.

For fuel oil firing, NO_x emissions of 42 ppmvd @ 15 percent O_2 are based on fuel bound nitrogen (FBN) content of 0.015 percent by weight or less. When FBN levels are above this percentage, the CTs may produce higher NO_x concentrations due to increased fuel NO_x formation. When FBN levels are above 0.015 percent, the operator shall employ all reasonable measures to maintain the NO_x concentrations below 42 ppmvd. However, NO_x emissions (ppmvd and lb/hr), as calculated from the formula below, shall be allowed if the permittee submits data (FBN levels from most recent fuel shipment or as fired fuel sampling and hourly averages of: fuel rate, heat rate, ambient conditions, and NO_x control system parameters) which demonstrates that emissions (hourly averages) above 42 ppmvd are due solely to FBN levels above 0.015 percent.

The emission level for NO_x is adjusted for higher fuel nitrogen contents up to a maximum of 0.030 percent by weight as follows:

FUEL BOUND NITROGEN (% by weight)	NO_x LEVELS (ppmvd @ 15% O_2)	NO_x EMISSIONS (lb/hr/CT)[1]	NO_x EMISSIONS INCREASE (TPY)[1]
0.015 or less	42	336.2	0
0.020	44	352.1	0
0.025	46	368.2	0
0.030	48	384.2	0

1 - From 336.2 lb/hr/CT at 32^0F basis.

For intermediate values of FBN use the formula:

STD = 0.0042 + F
where,
STD = allowable NO_x emissions (ppmvd @ 15% O_2)
F = NO_x emission allowance for fuel bound nitrogen
and
N (fuel bound nitrogen), is defined as follows:

N (% by weight)	F (NO_x % by volume)
$0<N\leq 0.015$	0
$0.015<N\leq 0.030$	0.04 (N-0.015)
$0.030<N$	0.0006

2. The following estimated CT emissions are tabulated for PSD tracking purposes only:

ESTIMATED EMISSIONS

POLLUTANT	**FUEL**	**TPY**
Lead	Oil(a,b)	0.16
Fluoride	Oil(a,b)	0.090
Mercury	Gas(c)	0.0003
	Oil(a,b)	0.024

(a) The annual emission limitations (TPY) for fuel oil are based on full-load operation for a total of 3,000 hours per year between the two CTs at an ambient temperature of 59°F.

(b) The No. 2 fuel oil shall have a maximum sulfur content limit of 0.05 percent, by weight.

(c) The annual emission limitation (TPY) for natural gas is based on two CTs operating at full-load for 8,760 hours per year at an ambient temperature of 59°F.

3. The permittee will install a dry low-NO_x (DLN) combustor or an SCR system on each CT. Ammonia slip from the SCR system shall not exceed 10 ppm. The permittee shall make every practicable effort to achieve the lowest possible NO_x emission rate, but must not exceed 12 ppmvd at 15 percent O_2 per CT on a continuous basis when firing natural gas during the first year of operation. The final limit for NO_x one year after startup will be 9 ppmvd at 15% O_2.

4. Excess emissions from a turbine resulting from start up, shutdown, malfunction, fuel switch or load change shall be reported in accordance with 40 CFR 60.334(c) and accepted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized, but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for a longer duration. The permittee shall provide a general description of the procedures to be followed during periods of start up, shutdown, malfunction, fuel switch or load change to ensure that the best operational practices to minimize emissions will be adhered to and the duration of any excess emissions will be minimized. The description should be submitted to the Department along with the initial compliance test data. The description may be updated as needed by submitting such update to the Department within thirty (30) days of implementation.

5. Excess emissions from fuel switching shall not exceed 15 minutes.

6. Excess emissions due to fuel bound nitrogen levels above 0.015 percent are allowed pursuant to Condition B.1 foot note (e) of the emission limitation table.

C. Performance Testing

1. Initial (I) compliance tests shall be performed on each CT using both fuels. Testing of emissions shall be conducted at 95-100% of the manufacturer's rated heat input based on the average ambient air temperature for the CT during the test. Annual (A) compliance tests shall be performed on the CT with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests at permit renewal shall also be performed on the non-PSD pollutants. Tests and procedures shall be in accordance with 40 CFR 60.335. Tests shall be conducted using EPA reference methods in accordance with 40 CFR 60, Appendix A, as adopted by reference in Chapter 62-297, F.A.C, and follows:

a. Reference Method 5B for PM (I, A: for oil only; assumption is that all PM is PM_{10}).

b. Reference Method 9 for VE (I, A).

c. Reference Method 10 for CO (I, A).

d. Reference Method 20 for NOx (I, A) or Method 7E if sampling downstream of the heat recovery steam generator.

e. Reference Method 18 or 25A for VOC (I, A).

f. Reference Method 8 for H_2SO_4 Mist (I, A).

g. Trace elements of Beryllium (Be) and Arsenic (As) shall be tested (I, for oil only) using EMTIC Interim Test Methods. As an alternative, EPA Method 104 for Be may be used; or, Be and As may be determined from fuel analysis using either Method 7090 or 7091 and sample extraction using Method 3040, as described in the EPA solid waste regulations SW 846.

h. ASTM D4294 (or equivalent) for sulfur content of distillate oil (I and A), which can be used for determining SO_2 emissions annually.

i. ASTM D1072-80, D3031-81, D4084-82, or D3246-81 (or equivalent) for sulfur content of natural gas (I; and, A if deemed necessary by the Department).

j. Other USEPA or DEP approved test methods for the permitted facilities may be used for compliance testing after departmental approval. Unless the permittee requests to modify a reference method, or to use a method for which a method was not designed, such approval shall not constitute an alternative test procedure under Section 62-297.620, F.A.C., or otherwise require modification of the permit.

2. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334(b).

3. As an alternative to Condition C.1.i above, natural gas supplier data for sulfur content may be submitted. However, the applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. 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 pursuant to 40 CFR 60.335(e) (1993 version). Any request for a future custom monitoring schedule shall be made in writing to the Department's Bureau of Air Regulation. Any custom schedule approved by the USEPA pursuant to 40 CFR 60.334(b) (1993 version) will be recognized as enforceable provisions of the permit.

D. Monitoring Requirements

Monitoring of operations shall be in accordance with 40 CFR 60.334. Also, and for each CT, the permittee shall install, operate, and maintain a continuous emission monitoring system (CEMS) to monitor nitrogen oxides in accordance with 40 CFR 60, Appendix F, and, if necessary, a diluent gas (CO_2 or O_2). The Federal Acid Rain Program requirements of 40 CFR 75 shall apply.

1. Each CEMS shall meet performance specifications of 40 CFR 60, Appendix B.

2. CEMS data shall be recorded and reported in accordance with Rule 62-297.500, F.A.C.; 40 CFR 60; and, 40 CFR 75, if it becomes applicable. The record shall include periods of start up, shutdown, load change, fuel switch, high fuel bound nitrogen, and malfunction.

3. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

4. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of all CEMS. In addition, 40 CFR 75 shall apply(Federal Acid Rain Program).

5. For purposes of the reports required under this permit, excess emissions, as determined pursuant to Condition B.6 herein, are defined as any calculated average emission rate which exceeds the applicable emission limitation in Condition B.1.

E. Notification, Reporting and Recordkeeping

1. To determine compliance with the natural gas and fuel oil firing heat input limitation, the permittee shall maintain daily records of natural gas and fuel oil consumption for each turbine, and provide the heating value for each fuel during the compliance test. All records shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Department upon request.

2. The project shall comply with all the applicable requirements of Chapters 62-210 through 62-297 and 62-4, F.A.C., and 40 CFR 60, Subparts A and GG. The requirements shall include:

a. 40 CFR 60.7(a)(1) - By postmarking or delivering notification of the start of construction no more than 30 days after such date.

b. 40 CFR 60.7(a)(2) - By postmarking or delivering notification of the anticipated date of the initial start up of each CT not less than 30 days prior to such date.

c. 40 CFR 60.7(a)(3) - By postmarking or delivering notification of the actual start up of each turbine within 15 days after such date.

d. 40 CFR 60.7(a)(5) - By postmarking or delivering notification of the date for demonstrating the CEMS performance, no less than 30 days prior to such date.

e. 40 CFR 60.7(a)(6) - By postmarking or delivering notification of the anticipated date for conducting the opacity observations no less than 30 days prior to such date.

f. 40 CFR 60.7(b) - By initiating a recordkeeping system to record the occurrence and duration of any start up, shutdown, load change, fuel switch, high fuel bound nitrogen, and malfunction of a turbine, malfunction of the air pollution control equipment, and the periods when the CEMS is inoperable.

g. 40 CFR 60.7(c) - By postmarking or delivering a quarterly excess emissions and monitoring system performance report within 30 days after the end of each calendar quarter. This report shall contain the information specified in 40 CFR 60.7(c) and (d).

h. 40 CFR 60.8(a) - By conducting all performance tests within 60 days after achieving the maximum turbine and boiler firing rates, but not more than 180 days after the initial start up of each CT.

i. 40 CFR 60.8(d) - By postmarking or delivering notification of the date of each performance test required by this permit at least 30 days prior to the test date; and,

j. Rule 62-297.345 - By providing stack sampling facilities for each turbine.

k. All notifications and reports required by this specific condition shall be submitted to the Department's Southwest District office. Performance test results shall be submitted within 45 days of completion of such test.

3. The following information shall be submitted to the Department's Bureau of Air Regulation within 90 days after the permittee has made the selection of the following:

a. Description of the final selection of the turbines, SCR and CO oxidation catalyst control systems. The descriptions shall include the specific make and model numbers and any changes in the proposed method of operation, fuels, emissions or equipment.

b. Description of the CEMS selected. The description shall include the type of sensors and the manufacturer and model numbers of the equipment.

4. The following protocols shall be submitted to the Department's Southwest District office for approval:

a. CEMS Protocol - Within 120 days after selection of the CEMS, but 180 days prior to the initial startup, a CEMS protocol describing the system, its installation, operating and maintenance characteristics and requirements. The protocol shall meet the requirements of 40 CFR 60.13, Appendix B and Appendix F or 40 CFR 75, and be approved within 60 days.

b. Performance Test Protocol - At least 90 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the Department's Southwest District office a protocol outlining the procedures to be followed, the test methods and any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit. The Department shall approve the testing protocol within 60 days provided that it meets the requirements of this permit.

c. Heat Input Curves - Within 120 days after final selection of the turbine, but 180 days prior to initial startup of the turbine, manufacturer's curves or equations of heat input and NOx emission rate (lbs/hr)corrections to other temperatures shall be provided to the Department.

d. Subject to the approval by the Department for technical validity while applying sound engineering principles, the manufacturer's curves shall be used to establish the heat input rates over a range of temperatures for the purposes of compliance determination.

F. Modifications

The permittee shall give written notification to the Department when there is any modification to this facility pursuant to Rule 62-212.200, F.A.C., Definitions - Modifications. 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.

G. No. 2 Fuel Oil Storage Tank

The permittee shall be in compliance with the monitoring requirements of 40 CFR 60.116b(a) and (b).

H. Additional General Conditions

1. Pursuant to Rule 62-4.090, F.A.C., the permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation prior to 60 days before the expiration of the permit.

2. An application for an operation permit pursuant to Rule 62-4.220, F.A.C., is not required if the facility is also certified under the Power Plant Siting Act, Chapter 403, Part II, F.S. That certification serves as the operation permit also. The permittee must submit an application for an operation permit for a major source of pollution pursuant to Chapter 62-213, F.A.C.

3. Approval to construct shall become invalid if construction is not commenced by June, 2000, if construction is discontinued for a period of 18 months or more, or if construction is not completed by March 4, 2002. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].