NOTICE OF FINAL TITLE V AIR OPERATION PERMIT

In the Matter of an
Application for Air Permit Renewal:

Wade A. Maye, General Manager
H. L. Culbreath Bayside Power Station
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601-0111

Final Permit No. 0570040-023-AV
H. L. Culbreath Bayside Power Station
Hillsborough County

Enclosed is the Final Permit, No. 0570040-023-AV. The purpose is for the renewal of the Title V Air Operation Permit and to incorporate the terms and conditions of air construction Permit No. PSD-FL-301A for Bayside Units 1 and 2. The facility is located in Hillsborough County. This permit renewal is issued pursuant to Chapter 403, Florida Statutes (F.S.). There were no comments received from Region 4, U.S. EPA, regarding the PROPOSED Permit.

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.

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL TITLE V AIR OPERATION PERMIT (including the FINAL Determination and the FINAL Permit) was sent by certified mail before the close of business on 12/28/04 to the person listed or as otherwise noted:

Wade A. Maye, TECO

The undersigned duly designated deputy agency clerk hereby certifies that a copy of this NOTICE OF FINAL TITLE V AIR OPERATION PERMIT was sent by INTERNET E-mail Memorandum before the close of business on 12/28/04 to the persons listed or as otherwise noted:

Ms. Greer Briggs, TECO
Ms. Raisa Calderon, TECO
Ms. Elena Vance, TECO
Mr. Tom Davis, P.E., ECT
Mr. Jerry Kissel, SWD Office
Mr. Jerry Campbell, HEPC
USEPA, Region 4

12/28/04 cc: Jeff Koerner Pending File

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Friday (Clerk) 12/28/04 (Date)

SENDER: *COMPLETE THIS SECTION*

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- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Wade A. Maye, General Manager
H.L. Culbreath Bayside Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

B. Received by (Printed Name) C. Date of Delivery

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Wade A. Maye, General Manager OFFICIAL USE

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Street, Apt. No.; or PO Box No. P. O. Box 111
City, State, ZIP+4
Tampa, Florida 33601-0111

PS Form 3800, June 2002 See Reverse for Instructions

Project

Final Permit No. 0570040-023-AV
Title V Air Operation Permit Renewal
Tampa Electric Company
H. L. Culbreath Bayside Power Station

EPA Comments

No comments were received from the U.S. EPA during their 45 day review period of the PROPOSED Permit.

Corrections

The Department made the following corrections:

1. Appendix AR: Changed the Title of "Appendix AR" from "Phase II Acid Rain Permit Application" to "Phase II Aid Rain Part and Retired Unit Exemption". This change was also made on the placard page as well as the table of contents to the Appendices.
2. Relevant Documents: Deleted the references to the "Phase II Acid Rain Part" and the "Retired Unit Exemption" as "relevant documents" on Page 3, Section I, Subsection C. These documents are included in Appendix AR as a part of the permit.
3. Table B-1: Deleted the "?" after the throughput rate for Emissions Point OMH-004 in Table B-1 on Page 16, Section III, Subsection B.

Conclusion

In conclusion, the changes that have been made are insignificant in nature and do not impose additional public noticing requirements. The permitting authority hereby issues the FINAL Permit, with the changes noted above.

Title V Permit Project

Project: Title V Air Operation Permit Renewal
Permit No. 0570040-023-AV
Applicant: Tampa Electric Company
Plant: H. L. Culbreath Bayside Power Station
Facility ID No.-0570040
Location: 3602 Port Sutton Road in Tampa, Hillsborough County, Florida

The purpose of this permit is to renew the Title V air operation permit for this facility, include the new Bayside Units 1 and 2 constructed pursuant to original Permit No. PSD-FL-301, and to incorporate the revised conditions of air construction Permit No. PSD-FL-301B (the draft of which was issued simultaneously with the Draft Title V renewal permit). The PSD air construction permit authorized the re-powering of existing F. J. Gannon steam turbine-electrical generators for Unit 5 and 6 with combined cycle gas turbines firing natural gas. The associated coal-fired boilers have been permanently shut down. The new gas turbines for Bayside Units 1 and 2 have been constructed and are in operation. For a discussion of the revisions included in Permit No. PSD-FL-301B, see the Technical Evaluation and Preliminary Determination included in this package.

Facility Description

The H. L. Culbreath Bayside Power Station is an electric power plant consisting of Bayside Units 1 and 2. Bayside Unit 1 is a "3-on-1" combined cycle gas turbine system with a nominal generating capacity of 746 MW. Bayside Unit 2 is a "4-on-1" combined cycle gas turbine system with a nominal generating capacity of 1090 MW. Based on the application to renew the Title V air operation permit received on July 2, 2004:

Title III: The facility is not a major source of hazardous air pollutants (HAPs).

Title IV: The gas turbines are subject to the Phase II Acid Rain program.

Title V: The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.

PSD: The facility is a PSD-major facility pursuant to Rule 62-212.400, F.A.C.

PPSC: The facility is not subject to power plant site certification.

NESHAP: The gas turbines are considered "existing units" with regard to National Emissions Standard for Hazardous Air Pollutants for stationary combustion turbines in Subpart YYYY of 40 CFR 63.

NSPS: The gas turbines are subject to the New Source Performance Standards for stationary gas turbines in Subpart GG of 40 CFR 60.

New Emissions Units

The new units are described as follows.

EU No.	Bayside Gas Turbine (GT)		Steam Turbines (ST)		Total
	Unit No.	MW, Shaft	Unit No.	MW, Steam	
020	CT-1A	169 MW	No. 5	239	746
021	CT-1B	169 MW			
022	CT-1C	169 MW			
023	CT-2A	169 MW	No. 6	414	1090
024	CT-2B	169 MW			
025	CT-2C	169 MW			
026	CT-2D	169 MW			
Totals	7 GTs	1183 MW	2 STs	653	1836

Description: Each emissions unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack, and associated support equipment. The project also includes electric fuel heaters and cooling towers.

Stack: Each gas turbine has a single exhaust stack that is 150 feet tall and 19.0 feet in diameter. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,000 acfm at 220° F.

Heat Input: Natural gas is the exclusive fuel. At a compressor inlet air temperature of 59° F and firing 1842 MMBtu (HHV) per hour of natural gas, each unit produces a nominal 169 MW of shaft-driven electricity.

Generating Capacity: The nameplate generating capacity is shown above for the steam turbine-electrical generators (ST). The final design may not fully utilize the nameplate generating capacity.

Controls: The efficient combustion of natural gas at high temperatures minimizes the emissions of carbon monoxide (CO), particulate matter (PM/PM10), and volatile organic compounds (VOC). Firing natural gas as the exclusive fuel minimizes emissions of sulfuric acid mist (SAM) and sulfur dioxide (SO_2) because natural gas contains only small amounts of sulfur. A selective catalytic reduction (SCR) system combined with dry low-NOx (DLN) combustion technology reduces nitrogen oxides (NOx) emissions. A Continuous Assurance Monitoring (CAM) Plan is not required for the SCR systems because NOx is continuously monitored for compliance.

Continuous Monitors: Each gas turbine is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx emissions as well as flue gas carbon dioxide content.

CAM Plan: There is a standard for CO emissions, but there is no add-on control device required. Although an SCR system is operated to achieve the NOx standard, compliance is continuously demonstrated by CEMS. Therefore, a Compliance Assurance Monitoring (CAM) Plan is not required for these units.

{Permitting Notes: These emissions units are regulated under: NSPS Subpart GG (Gas Turbines) in 40 CFR 60 adopted and incorporated by reference in Rule 62-204.800, F.A.C.; the Prevention of Significant Deterioration (PSD) as specified in Permit No. PSD-FL-301 (as modified) and Rule 212.400, F.A.C.; the Best Available Control Technology (BACT) for carbon monoxide (CO), particulate matter (PM/PM10), and volatile organic compounds (VOC) as specified in Permit No. PSD-FL-301 (as modified) and Rule 62-212.400(6), F.A.C.; and the Phase II Acid Rain Program as specified in Section IV of this permit.}

Previously Existing Emissions Units

This facility consists of the following emissions unit remaining from the F. J. Gannon Station.

EU No.	Description
008	F. J. Gannon Station Fuel Yard

Description: Activities related to the existing fuel yard include: barge unloading of coal (clamshell and continuous); railcar unloading of coal; truck, barge, and train unloading of flux; and the transfer and storage of these materials.

Fugitive Emissions Control: Loading and unloading activities are controlled by enclosures and dust suppressants. Rotoclones control two conveyors. Water sprays or chemical wetting agents and stabilizers are used coal storage piles as necessary.

Primary Regulatory Requirements: These activities are subject to the following requirements: Rule 62-296.711, F.A.C. (Materials Handling, Sizing, Screening, Crushing and Grinding Operation); and Rule 62-296.700, F.A.C. (Reasonably Available Control Technology (RACT) for Particulate Matter). The coal yard is not currently in operation. The existing fuel yard equipment served F. J. Gannon Station Units 1 through 6. The coal-fired Gannon boilers are permanently shut down and are included as "Retired Units" in the Acid Rain Part of the Title V permit (Subsection B, Section IV).

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Conclusion

Based on reasonable assurances of compliance provided by the applicant and the Responsible Official's certification of compliance, the Department intends to issue a Title V Air Operation Permit under the provisions of Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-210, 62-213 and 62-214 of the Florida Administrative Code (F.A.C.). The permit authorizes operation of the facility shown on the application and approved drawings, plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

TITLE V AIR OPERATION PERMIT
FINAL PERMIT NO. 0570040-023-AV

Permittee

Facility ID No. 0570040
Tampa Electric Company
H. L. Culbreath Bayside Power Station
3602 Port Sutton Road in Tampa
Hillsborough County, Florida

Permitting Authority

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation - Air Permitting South Program
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

Compliance Authority

Environmental Protection Commission of Hillsborough County
1410 North 21st Street
Tampa, Florida 33605

Telephone: 813/272-5530
Fax: 813/272-5605

Table of Contents

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

TITLE V AIR OPERATION PERMIT

Permittee:
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

H. L. Culbreath Bayside Power Station
Facility ID No 0570040
Final Permit No. 0570040-023-AV

This Title V air permit authorizes operation of the H. L. Culbreath Bayside Power Station, which is located in Hillsborough County at Port Sutton Road in Tampa, Hillsborough County, Florida. The permit is a renewal of the initial Title V air operation permit for this existing facility (formerly the F. J. Gannon Station) as well as a revision to incorporate the new Bayside combined cycle gas turbine Units 1 and 2. The Standard Industrial Classification (SIC) code for this electric power plant is 4911. The UTM Coordinates are: Zone 17, 360.1 km East and 3087.5 km North (Latitude: 28° 02' 31" North and Longitude: 82° 25' 31" West).

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to operate the facility shown on the application and approved drawings, plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Appendices

The following appendices are a part of this permit.

Appendix A-1. Citation Formats
Appendix AR. Phase II Acid Rain Part Application and Retired Unit Exemption
Appendix BD. Final BACT Determinations and Emissions Standards (Gas Turbines)
Appendix CD. Consent Decree (U.S. EPA vs. TECO)
Appendix CFJ. Consent Final Judgment (DEP vs. TECO)
Appendix CT. Common Compliance Test Requirements
Appendix I-1. List of Insignificant Emissions Units and/or Activities
Appendix GG. NSPS Subpart GG Requirements for Stationary Gas Turbines
Appendix TV-4. Title V Conditions
Appendix XS. Semi-Annual Continuous Monitor Systems Report

Effective Date: January 1, 2005
Renewal Application Due Date: July 5, 2009
Expiration Date: December 31, 2009

Michael G. Cooke, Director
Division of Air Resource Management

Subsection A. Facility Description

The H. L. Culbreath Bayside Power Station is an electric power plant primarily consisting of Bayside Units 1 and 2. Bayside Unit 1 is a "3-on-1" combined cycle gas turbine system with a nominal generating capacity of 746 MW. Bayside Unit 2 is a "4-on-1" combined cycle gas turbine system with a nominal generating capacity of 1090 MW. These units fire natural gas as the exclusive fuel and employ selective catalytic reduction (SCR) to reduce emissions of nitrogen oxides.

Based on the application to renew the Title V air operation permit received on July 2, 2004:

Title III: The facility is not a major source of hazardous air pollutants (HAPs).

Title IV: The gas turbines are subject to the Phase II Acid Rain requirements.

Title V: The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.

PSD: The facility is a PSD-major facility pursuant to Rule 62-212.400, F.A.C.

PPSC: The facility is not subject to power plant site certification.

NESHAP: No regulated units are subject to a National Emissions Standard for Hazardous Air Pollutants. The gas turbines are considered "existing units" in accordance with Subpart YYYY of 40 CFR 63.

NSPS: The gas turbines are subject to the New Source Performance Standards in Subpart GG of 40 CFR 60.

Subsection B. Emissions Units Summary

This permit specifically regulates the following emissions units.

EU No.	Brief Description
008	F. J. Gannon Station Fuel Yard
Bayside Unit 1 - Three combined cycle gas turbines with one steam-electrical generator (746 MW, total)	
020	CT-1A – Combined cycle gas turbine (169 MW, shaft)
021	CT-1B – Combined cycle gas turbine (169 MW, shaft)
022	CT-1C – Combined cycle gas turbine (169 MW, shaft)
Bayside Unit 2 - Four combined cycle gas turbines with one steam-electrical generator (1090 MW, total)	
023	CT-2A – Combined cycle gas turbine (169 MW, shaft)
024	CT-2B – Combined cycle gas turbine (169 MW, shaft)
025	CT-2C – Combined cycle gas turbine (169 MW, shaft)
026	CT-2D – Combined cycle gas turbine (169 MW, shaft)

Other than the fuel yard identified above, the F. J. Gannon Units 1 - 6 and other emissions units associated with the coal-fired boilers are permanently shut down (Emissions Units 001 through 007 and 009 through 019). This facility also includes other miscellaneous insignificant emissions units and activities. Please reference the permit number, facility identification number, and the corresponding emissions unit identification numbers on all correspondence, test submittals, applications, etc.

Subsection C. Relevant Documents

The following documents are not a part of this permit; however, they are specifically related to this permitting action and are on file with permitting authority.

- Application to revise the Title V air operation permit to incorporate Units 1 and 2 received on May 5, 2004;
- EPCHC comments dated May 26, 2004;
- Department's request for additional information dated June 4, 2004;
- Additional information from TECO submitted on September 2, 2004;
- Application to renew Title V air operation permit received July 2, 2004;
- Risk Management Plan submitted to the RMP Reporting Center dated June 18, 2004;
- Department's request for additional information dated August 27, 2004;
- EPCHC comments dated August 24, 2004;
- The applicant's response to the request for additional information dated October 1, 2004 (email);
- Draft Title V Permit issued on October 5, 2004;
- Public notice published on October 9, 2004;
- Proposed Title V Permit posted for U.S. EPA review on November 8, 2004; and
- Statements of Basis provided with draft, proposed, and final permits.

{Permitting Note: An application for permit revision to incorporate Bayside Units 1 and 2 into the existing Title V air operation permit for the F. J. Gannon Station was received on May 5, 2004. An application to renew the Title V air operation permit was received on July 2, 2004. Because of the substantial changes at this facility, these two applications were combined into a single project to renew the Title V air operation permit.}

The following conditions apply facility-wide.

ADMINISTRATIVE REQUIREMENTS

II.1 Title V Conditions: The Title V Conditions in Appendix TV-4 are a part of this permit, but are distributed only to the permittee. Other persons shall be provided a copy when requested or otherwise appropriate. [Florida Administrative Code]

II.2 Insignificant Emissions Units and/or Activities. Insignificant emissions units and/or activities are identified in Appendix I-1, which is a part of this permit. [Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

II.3 Settlement Agreements: The Consent Final Judgment (DEP vs. TECO, dated December 6, 1999) and the Consent Decree (U.S. vs. TECO, dated February 29, 2000) are made a part of this permit and attached as Appendices CFJ and CD, respectively. The permittee shall comply with the Consent Final Judgment and the Consent Decree. If conditions of this permit conflict with the Consent Decree, the terms and conditions of the Consent Decree control. Upon expiration of the Consent Decree the Title V permit shall be modified to incorporate any terms and conditions that are deemed necessary by the permitting authority for the continued operation of the facility. [Rules 62-4.070(3), (5) and 62-213.440, F.A.C.]

II.4 Date of Records: When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one. [Rule 62-213.440, F.A.C.]

II.5 Statement of Compliance: The annual statement of compliance shall be submitted to the Department and EPA within sixty (60) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C. *{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2 and 3, F.A.C. See also Condition 51 in Appendix TV-4.}* [Rule 62-213.440(3)(a)2, F.A.C.]

II.6 Certification by Responsible Official (R.O.): In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information. [Rule 62-213.420(4), F.A.C.]

II.7 Compliance Authority: The permittee shall submit all compliance related notifications and reports required of this permit to the Air Management Division of the Environmental Protection Commission of Hillsborough County at 1410 North 21st Street, Tampa, Florida 33605. The telephone number is 813/272-5530 and the fax number is 813/272-5605.

II.8 Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Florida Department of Environmental Protection's Bureau of Air Regulation at 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The telephone number is 850/488-0114 and the fax number is 850/922-6979. Copies of all applications shall also be provided to the Compliance Authority and the EPA Region 4 Office.

II.9 EPA Region 4 Office: Any reports, data, notifications, certifications, and requests required to be sent to the EPA Region 4 Office should be sent to: United States Environmental Protection Agency - Region 4; Air, Pesticides & Toxics Management Division; Air and EPCRA Enforcement Branch; Air Enforcement Section; 61 Forsyth Street, Atlanta, Georgia 30303-8960. The telephone number is 404/562-9155 and the fax number is 404/562-9163.

II.10 Prevention of Accidental Releases: The Responsible Official has certified that the Risk Management Plan was submitted to the RMP Reporting Center.

a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center.

b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.

c. The owner or operator shall submit the required annual registration fee to the DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S., and Rule 9G-21, F.A.C.

d. Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to: Department of Community Affairs, Division of Emergency Management, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2100. The telephone number is 850/413-9921 and the fax number is 850/488-1739.

Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to: RMP Reporting Center, Post Office Box 1515, Lanham-Seabrook, Maryland 20703-1515. The telephone number is 301/429-5018.

Any required reports to be sent to the National Response Center, should be sent to: National Response Center; EPA Office of Solid Waste and Emergency Response; USEPA (5305 W); 401 M Street, SW; Washington, D.C. 20460. The telephone number is 1/800/424-8802.

Send the required annual registration fee using approved forms made payable to: Cashier, Department of Community Affairs; State Emergency Response Commission; 2555 Shumard Oak Boulevard; Tallahassee, FL 32399-2149.

{Permitting Note: This facility handles and stores anhydrous ammonia.} [Part IV, Chapter 252, F.S.; and, Rule 9G-21, F.A.C.]

EMISSIONS AND CONTROLS

II.11 Excess Emissions Allowed: Unless otherwise specified in this permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted 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 longer duration. [Rule 62-210.700(1), F.A.C.]

II.12 Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

II.13 Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

II.14 VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. Nothing

was deemed necessary and ordered at this time. [Rule 62-296.320(1)(a), F.A.C.; application for Title V permit renewal received July 2, 2004]

II.15 Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Permit No. PSD-FL-301A; Rules 62-296.320(2) and62-210.200(203), F.A.C.]

II.16 General Visible Emissions Standard: Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the opacity of which is equal to or greater than 20 percent. EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C. [Rule 62-296.320(4)(b)1 and 4, F.A.C.]

II.17 Emissions of Unconfined Particulate Matter: The following activities may result in unconfined particulate matter: vehicular traffic on paved and unpaved roads; wind-blown dust from yard areas; and periodic abrasive blasting. The following reasonable precautions shall be taken as necessary to control the emissions of unconfined particulate matter: applying chemicals or water to unpaved roads and unpaved yard areas; paving and maintenance of roads, parking areas, and yards; landscaping or planting of vegetation; and confining abrasive blasting when possible. Other techniques may be deemed appropriate as necessary. See also Condition 57 in Appendix TV-4. [Rule 62-296.320(4)(c), F.A.C.; Application for Title V permit renewal received July 2, 2004]

DESCRIPTION OF EMISSIONS UNITS

The specific conditions in this subsection apply to the following emissions units.

Emissions Units 020 – 026: Combined Cycle Gas Turbines

EU No.	Bayside Gas Turbine (GT)		Steam Turbines (ST)		Total
	Unit No.	MW, Shaft	Unit No.	MW, Steam	
020	CT-1A	169 MW	No. 5	239	746
021	CT-1B	169 MW			
022	CT-1C	169 MW			
023	CT-2A	169 MW	No. 6	414	1090
024	CT-2B	169 MW			
025	CT-2C	169 MW			
026	CT-2D	169 MW			
Totals	7 GTs	1183 MW	2 STs	653	1836

Description: Each emissions unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack, and associated support equipment. The project also includes electric fuel heaters and cooling towers.

Stack: Each gas turbine has a single exhaust stack that is 150 feet tall and 19.0 feet in diameter. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,000 acfm at 220° F.

Heat Input: Natural gas is the exclusive fuel. At a compressor inlet air temperature of 59° F and firing 1842 MMBtu (HHV) per hour of natural gas, each unit produces a nominal 169 MW of shaft-driven electricity.

Generating Capacity: The nameplate generating capacity is shown above for the steam turbine-electrical generators (ST). The final design may not fully utilize the nameplate generating capacity.

Controls: The efficient combustion of natural gas at high temperatures minimizes the emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). Firing natural gas as the exclusive fuel minimizes emissions of sulfuric acid mist (SAM) and sulfur dioxide (SO_2) because natural gas contains only small amounts of sulfur. A selective catalytic reduction (SCR) system combined with dry low-NOx (DLN) combustion technology reduces nitrogen oxides (NOx) emissions. A Continuous Assurance Monitoring (CAM) Plan is not required for the SCR systems because NOx is continuously monitored for compliance.

Continuous Monitors: Each gas turbine is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NOx emissions as well as flue gas carbon dioxide content.

CAM Plan: There is a standard for CO emissions, but there is no add-on control device required. Although an SCR system is operated to achieve the NOx standard, compliance is continuously demonstrated by CEMS. Therefore, a Compliance Assurance Monitoring (CAM) Plan is not required for these units.

{Permitting Notes: These emissions units are regulated under: NSPS Subpart GG (Gas Turbines) in 40 CFR 60 adopted and incorporated by reference in Rule 62-204.800, F.A.C.; the Prevention of Significant Deterioration (PSD) as specified in Permit No. PSD-FL-301 (as modified) and Rule 212.400, F.A.C.; the Best Available Control Technology (BACT) for carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC) as specified in Permit No. PSD-FL-301 (as modified) and Rule 62-212.400(6), F.A.C.; and the Phase II Acid Rain Program as specified in Section IV of this permit.}

EQUIPMENT AND MODIFICATIONS

A.1 Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Permit No. PSD-FL-301A; Rules 62-210.200 and 62-210.300(1), F.A.C.]

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

A.2 Permitted Capacity: The maximum heat input rate to each gas turbine shall not exceed 1842 MMBtu per hour while producing approximately 169 MW (shaft). The maximum heat input rate is based on operation at 100% load, a compressor inlet air temperature of 59° F, the higher heating value (HHV) of natural gas and expected performance levels. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Permit No. PSD-FL-301A; Rules 62-4.160(2), 62-210.200(PTE), and 62-212.400(BACT), F.A.C.]

A.3 Allowable Fuels: Each gas turbine shall fire only pipeline-quality natural gas. The fuel sulfur content shall not exceed 2 grains per 100 SCF of natural gas based on a 12-month rolling average. Compliance shall be demonstrated each month by compiling the daily fuel sulfur analyses provided by the pipeline vendor. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods. No other fuels are allowed. [Permit No. PSD-FL-301A; Rules 62-210.200(PTE) and 62-213.410, F.A.C.; DEP/TEC Consent Final Judgment; EPA/TEC Consent Decree]

A.4 Hours of Operation: The hours of operation for each gas turbine are not limited (8760 hours per year). [Permit No. PSD-FL-301A; Rule 62-210.200(PTE), F.A.C.]

A.5 Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods to minimize emissions during startup and shutdown. [Permit No. PSD-FL-301A; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

AIR POLLUTION CONTROL EQUIPMENT

A.6 DLN Combustion Technology: The permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to provide efficient lean premix combustion. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Permit No. PSD-FL-301A; Rule 62-212.400(BACT), F.A.C.]

A.7 SCR System: The permittee shall install, tune, operate and maintain a selective catalytic reduction (SCR) system to reduce NOx emissions from each combined cycle gas turbine. The SCR system shall consist of an ammonia injection grid, catalyst, ammonia storage, a monitoring and control system, electrical system, piping, and other ancillary equipment. The SCR system shall be designed to reduce NOx emissions while minimizing ammonia slip within the permitted levels. *{Permitting Note: In general, the SCR system is placed in service once the exhaust gas temperature reaches 446° F.}* [Permit No. PSD-FL-301A; DEP/TEC Consent Final Judgment; EPA/TEC Consent Decree; Rule 62-4.070(3), F.A.C.]

EMISSION LIMITATIONS AND STANDARDS

A.8 Emissions Standards Based on Performance Tests: The following standards apply to each combined cycle gas turbine as determined by emissions performance tests conducted at permitted capacity. The mass emission limits are based on a compressor inlet temperature of 59° F. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data shall be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

a. *Ammonia Slip*: Subject to the requirements of Condition A.15 in this section, each SCR system shall be designed and operated for an ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. [Rule 62-4.070(3), F.A.C.]

b. *Carbon Monoxide (CO)*: CO emissions shall not exceed 28.7 pounds per hour and 7.8 ppmvd corrected to 15% oxygen based on the average of three test runs as determined by EPA Method 10. [Rule 62-212.400(BACT), F.A.C.]

c. *Nitrogen Oxides (NOx)*: NOx emissions shall not exceed 23.1 pounds per hour and 3.5 ppmvd corrected to 15% oxygen based on the average of three test runs as determined by EPA Method 7E. NOx emissions are defined as oxides of nitrogen reported as NO_2. [DEP/TEC Consent Final Judgment; EPA/TEC Consent Decree; 40 CFR 60.332]

d. *Particulate Matter (PM/PM_{10})*: The exclusive firing of pipeline-quality natural gas combined with the efficient combustion design and operation of each gas turbine represent the Best Available Control Technology (BACT) requirements for particulate matter emissions. Compliance with carbon monoxide and visible emissions standards shall serve as continuous indicators of efficient combustion to minimize particulate matter emissions. No performance tests are required. [Rule 62-212.400(BACT), F.A.C.]

e. *Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2)*: The exclusive firing of pipeline-quality natural gas effectively limits potential emissions of SO_2 and SAM. No performance tests are required. [Design; DEP/TEC Consent Final Judgment; EPA/TEC Consent Decree; 40 CFR 60.333]

f. *Visible Emissions*: Visible emissions shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. Except as allowed by Condition A.11 of this section, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]

g. *Volatile Organic Compounds (VOC)*: The exclusive firing of pipeline-quality natural gas combined with the efficient combustion design and operation of each gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with carbon monoxide standards shall serve as a continuous indicator of efficient combustion to minimize VOC emissions. No performance tests are required. [Permit No. PSD-FL-301A; Rule 62-212.400(BACT), F.A.C.]

A.9 Emissions Standards Based on CEMS Data: The following standards apply to each gas turbine based on data collected from each required Continuous Emissions Monitoring System (CEMS).

a. *Carbon Monoxide (CO)*: CO emissions shall not exceed 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average of CEMS data.

b. *Nitrogen Oxides (NOx)*: NOx emissions shall not exceed 3.5 ppmvd corrected to 15% oxygen based on a 24-hour block average of CEMS data.

Each 24-hour block average shall start at midnight each operating day and shall be calculated from 24 consecutive 1-hour averages. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of the available valid 1-hour averages. [Permit No. PSD-FL-301A; Rules

62-212.400(BACT) and 62-4.070(3), F.A.C.]

STARTUP, SHUTDOWN, MALFUNCTION, AND LOW LOAD OPERATION

A.10 Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in the compliance averages determined from the CO and NOx CEMS data. [Permit No. PSD-FL-301A; Rule 62-210.700(4), F.A.C.]

A.11 Alternate Standards and CEMS Data Exclusion: The following permit conditions establish alternate standards or allow the exclusion of monitoring data for specifically defined periods of startup, shutdown, and malfunction. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of emissions during such incidents.

a. **Opacity During Startup and Shutdown**: During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

b. **Low Load Operation**: Excluding startup, shutdown, malfunction, DLN tuning, compressor blade drying, and over speed trip tests, each gas turbine may operate below 50% base load providing: the gas turbine is firing natural gas and operating in full dry low-NOx combustion mode; the CO and NOx CEMS are functioning properly during such periods and recording valid emissions data within the span range of the monitors; and the gas turbine remains in compliance with the CO and NOx emissions standards (24-hour block averages).

c. **CEMS Data Exclusion**: For the following specified operational periods, CO and NOx emissions data may be excluded from the 24-hour block compliance averages in accordance with the corresponding requirements.

(1) *Definitions*: Rule 62-210.200(231), F.A.C. defines "shutdown" as the cessation of the operation of an emissions unit for any purpose. Rule 62-210.200(160), F.A.C. defines "malfunction" as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. Rule 62-210.200(246), F.A.C. defines "startup" as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

(2) *Standard Startups, Shutdowns, and Malfunctions*: For each gas turbine, no more than four 1-hour CEMS emission averages shall be excluded from any 24-hour block compliance average due to standard startups, shutdowns, and malfunctions (total).

(3) *Cold Steam Turbine Startup*: "Cold steam turbine startup" means a startup after the steam turbine has been offline for 24 hours or more, or the first stage turbine metal temperature is 250° F or less. To minimize emissions, no more than one gas turbine per Bayside Unit shall be operated during a cold steam turbine startup. No more than sixteen 1-hour CEMS emission averages shall be excluded from the 24-hour block compliance averages due to a cold steam turbine startup. In addition, no more than sixteen 1-hour CEMS emission averages shall be excluded from any 24-hour block compliance average due to cold steam turbine startup. In the event of a cold steam turbine startup and standard startups, shutdowns and/or malfunctions within the same 24 hour period, a total of sixteen 1-hour CEMS emissions averages may be excluded with no more than four of those sixteen 1-hour CEMS emissions averages being

excluded due to standard startups, shutdowns, and malfunctions (total). This condition applies only to the gas turbine being used for the cold steam turbine startup. The permittee shall notify the Compliance Authority no later than 24 hours after beginning a cold steam turbine startup. Notification may be by phone, facsimile, email, or letter.

(4) *Steam Turbine Startup Following an Unplanned Forced Outage*: "Steam turbine startup following unplanned, forced outage" means startup when the first stage turbine metal temperature is 250° F or more and occurs within 24 hours after either (1) the steam turbine inadvertently trips offline, or (2) the plant is forced to take the steam turbine offline for repair. To minimize emissions, no more than one gas turbine per Bayside Unit shall be operated during a steam turbine startup following an unplanned forced outage. No more than eight 1-hour CEMS emissions averages shall be excluded from the 24-hour block compliance averages due to a steam turbine startup following an unplanned forced outage. In addition, no more than eight 1-hour CEMS emission averages shall be excluded from any 24-hour block compliance average due to steam turbine startups following an unplanned forced outage. In the event of a startup following an unplanned forced outage and standard startups, shutdowns and/or malfunctions within the same 24 hour period, a total of eight 1-hour CEMS emissions averages may be excluded with no more than four of those eight 1-hour CEMS emissions averages being excluded due to standard startups, shutdowns, and malfunctions (total). This condition applies only to the gas turbine being used for steam turbine startup following an unplanned forced outage. The permittee shall notify the Compliance Authority no later than 24 hours after beginning a steam turbine startup following an unplanned forced outage. Notification may be by phone, facsimile, email, or letter and shall include the reason for the unplanned forced outage.

(5) *DLN Tuning*: "DLN Tuning" means operating the gas turbine at intermittent loads throughout the full load range in order to adjust and tune the dry low-NOx (DLN) combustion system. DLN tuning shall be conducted in accordance with manufacturer' recommendations. Emissions data collected during DLN tuning may be excluded from the 24-hour block compliance averages. *{Permitting Note: For example, a major tuning session would occur after combustor change-out.}*

(6) *Compressor Blade Drying*: Following a compressor blade wash in accordance with the manufacturer's recommendations, the permittee may operate a gas turbine at very low loads to heat and dry the compressor blades. Emissions data collected while drying the compressor blades may be excluded from the 24-hour block compliance averages. *{Permitting Note: A gas turbine would typically operate at approximately 10% of base load or less to perform compressor blade drying.}*

(7) *Over Speed Trip Test*: As a periodic maintenance practice, the permittee may perform over speed trip tests in accordance with the manufacturer's recommendations. Emissions data collected while conducting over speed trip tests may be excluded from the 24-hour block compliance averages. *{Permitting Note: During this test, the gas turbine is operated at full speed, no load (FSNL) for approximately 5 to 6 hours. The unit is gradually accelerated to 110% speed (3960 rpm) to initiate a trip and then coasts down normally. Over speed trip tests are typically performed after a long outage or a major component overhaul.}*

To the extent practicable, the permittee shall minimize the amount and duration of emissions during periods of startup, shutdown, malfunction, DLN tuning, compressor blade drying, and over speed trip testing. If a CEMS reports emissions in excess of an emissions standard (24-hour block), the permittee shall notify the Compliance Authority within one working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Compliance Authority may request a

written summary report of the incident. All emissions data allowed for exclusion shall be summarized in the Semiannual CEMS Report required in Condition A.20 of this subsection.

d. **Startup and Shutdown Plan**: The permittee shall maintain on site a "Startup and Shutdown Plan" that describes procedures for startup and shutdown of the Bayside Units.

As provided by the authority in Rule 62-210.700(5), F.A.C., the above requirements are established in lieu of the provisions of Rule 62-210.700(1), F.A.C.

{Permitting Note: The durations for a cold steam turbine startup and a steam turbine startup following an unplanned forced outage are not typical for combined cycle units. The Bayside Units utilize the existing Gannon steam turbines. Operating procedures require one gas turbine to operate at low loads for extended periods to gradually warm the main and hot reheat steam lines to the steam turbine as well as the steam turbine. Some steam lines are in excess of 1700 feet. Such startups are expected to occur infrequently.} [Design; Rules 62-4.130, 62-210.700(5), and 62-212.400 (BACT), F.A.C.; Permit No. PSD-FL-301B]

TEST METHODS AND PROCEDURES

A.12 Test Methods: Any test required shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	*Procedure for Collection and Analysis of Ammonia in Stationary Source*: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
5	*Determination of Particulate Matter Emissions from Stationary Sources*: The minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run.
7E	*Determination of Nitrogen Oxide Emissions from Stationary Sources*
9	*Visual Determination of the Opacity of Emissions from Stationary Sources*
10	*Determination of Carbon Monoxide Emissions from Stationary Sources*: The method shall use a continuous sampling train.
18	*Measurement of Gaseous Organic Compound Emissions by Gas Chromatography*: EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	*Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines*
25A	*Determination of Volatile Organic Concentrations*

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". Although no specific tests are required for emissions of particulate matter and volatile organic compounds, the test methods are included for completeness. No other methods may be used for compliance testing unless prior written approval is received from the Department. [Permit No. PSD-FL-301A; Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

A.13 Operating Rate During Testing: Emissions performance testing shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Permit No.

PSD-FL-301A; Rule 62-297.310(2), F.A.C.]

A.14 Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for ammonia slip and visible emissions. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. *{Permitting Note: Continuous compliance with the CO and NOx standards will be demonstrated with certified CEMS data.}* [Permit No. PSD-FL-301A; Rules 62-212.400(BACT) and 62-297.310(7)(a)4, F.A.C.]

A.15 Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Permit No. PSD-FL-301A; Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

A.16 Common Compliance Testing Requirements: Appendix CT of this permit identifies other compliance testing requirements commonly applicable to the emissions units in this subsection. [Florida Administrative Code]

MONITORING REQUIREMENTS

A.17 Monitoring of Operations: To demonstrate compliance with the gas turbine capacity requirements, the permittee shall monitor and record the operating rate of each gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEMS required above, or by monitoring daily rates of consumption and heat content of natural gas in accordance with the provisions of 40 CFR 75 Appendix D. [Permit No. PSD-FL-301A; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

A.18 Ammonia Monitoring Requirements: The permittee shall install, calibrate, maintain and operate, in accordance with the manufacturer's specifications, an ammonia flow meter to measure and record the ammonia injection rate through each SCR system. The permittee shall document the general range of ammonia flow rates required to meet emissions limitations over the range of gas turbine load conditions allowed in this permit by comparing NOx emissions recorded by the NOx monitor with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the gas turbine load. [Permit No. PSD-FL-301A; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

A.19 Continuous Emissions Monitoring Systems: The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) in the exhaust stack of each emissions unit to measure and record emissions of CO and NOx in a manner sufficient to demonstrate compliance with the CEMS emission standards of this permit. The carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. The oxygen content of the flue gas shall be calculated by the CEMS using the CO_2 content of the flue gas and an F-factor that is appropriate for natural gas.

a. *Emission Averages.* Compliance with the 24-hour standards for CO and NOx emissions shall be based on data collected by the required CEMS. The 24-hour block shall start at midnight of each operating day and consist of 24 consecutive 1-hour blocks. If a unit operates continuously throughout the day, the 24-hour block average shall be the average of 24 consecutive 1-hour emission averages. If a unit operates less than 24 hours during the day, the 24-hour block average shall be the average of available valid 1-hour emission averages collected during operation. If monitoring data is authorized for exclusion (due to startup, shutdown, malfunction, or tuning), the 24-hour block average shall be the average of the remaining available valid 1-hour emission averages collected during operation. Upon a request from the Compliance Authority, the NOx emission rate shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

b. *Data Collection.* The CEMS shall be designed and operated to sample, analyze, and record CO, CO_2, and NOx data evenly spaced over the hour. Each 1-hour emission average shall be computed using at least one data point in each fifteen minute quadrant of the 1-hour block during which the unit combusted fuel. Notwithstanding this requirement, each 1-hour emission average shall be computed from at least two data points separated by a minimum of 15 minutes. If the unit does not operate in more than one quadrant of a 1-hour block, the data is insufficient to determine a 1-hour emission average and shall be ignored. (Example: Unit begins startup with only ten minutes remaining in the 1-hour block. Data is insufficient to determine a 1-hour average and is ignored.) All valid measurements or data points collected during a 1-hour block shall be used to calculate the 1-hour emission averages. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, a curve of the flue gas moisture content versus load may be developed through manual stack test measurements and used in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). The CO and NOx CEMS shall express the 1-hour emission averages and the 24-hour block averages in terms of "ppmvd corrected to 15% oxygen".

c. *Data Exclusion.* CO, CO_2, and NOx emissions data shall be recorded by the CEMS at all times including episodes of startup, shutdown, malfunction, and tuning. CO and NOx emissions data recorded during such episodes may be excluded from the 24-hour block compliance averages in accordance with the requirements of Condition A.11 of this section. All periods of data excluded due to startup, shutdown or malfunction shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited. Excluded emissions shall be summarized in the required semiannual report.

d. *NOx Certification.* The NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the CEMS emission standards of this permit, missing data shall not be substituted. Instead the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 7E or 20 as defined in Appendix A of 40 CFR 60. The span for the NOx monitor shall not be greater than 10 ppmvd corrected to 15% O_2. A dual span monitor may be used.

e. *CO and CO_2 Certification.* The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. Quality assurance procedures for each monitor shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semi-annually to the Compliance Authority. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3A, of Appendix A in 40 CFR 60. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A in 40 CFR 60. The Method 10 analysis shall use a continuous sampling train. The span for the CO monitor shall not be greater than 25 ppm corrected to 15% oxygen. A dual span CO monitor may be used.

f. *Monitor Availability.* Monitor availability shall not be less than 95% in any calendar quarter. The report required in Condition A.19e above shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Compliance Authority with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEMS requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}

[Permit No. PSD-FL-301A; Rules 62-4.070(3), 62-210.700(5), and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

A.20 Semiannual CEMS Report: In addition to the reports required pursuant to 40 CFR 60.7, the permittee shall submit semiannual reports for each gas turbine summarizing the CEMS data and equipment. For each calendar quarter, the report shall include: the 24-hour block compliance averages for each day of operation; the number of 1-hour emission averages excluded from each 24-hour compliance average; the emissions rate of the excluded monitoring data; the reason for excluding monitoring data; the hours of missing data due to monitor downtime; the reason for any monitor downtime; unusual maintenance or repair of the CEMS; and a summary of any RATA tests performed. Based on operational data, the permittee shall also update the general range of ammonia flow rates required to meet NOx emissions limitations over the range of gas turbine load conditions. A report covering operations from January through June shall be submitted by July 30th of each year. A report covering operations from July through December shall be submitted by January 30th of each year. The report due dates may be modified by the Title V permit. [Permit No. PSD-FL-301A; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

Subsection B. Fuel Yard

DESCRIPTION OF EMISSIONS UNIT

The specific conditions in this subsection apply to the activities and equipment comprising Emissions Unit 008, which is the existing fuel yard. Activities related to the existing fuel yard include: barge unloading of coal (clamshell and continuous); railcar unloading of coal; truck, barge, and train unloading of flux; and the transfer and storage of these materials. The following table identifies the emissions points and particulate matter control equipment information.

Table B-1. Emission Point Summary for Fuel Yard

Emission Point Description	ID No.	Throughput TPH	Control Method	Efficiency
Barge to clamshell	FH-001/002	2,300	DS	95%
Barge to continuous unloader	FH-003	2,300	DS	95%
Clamshell to barge unloading hopper	FH-004/005	2,300	DS	95%
Continuous unloader to conveyor A	FH-006	2,300	**DS	95%
Conveyor A to continuous feeder	FH-007	2,300	DS/E	95%
Barge unloading hoppers to conveyor B	FH-008/009	2,300	**DS/E	95%
Conveyor B to conveyor C	FH-011	2,300	DS/E	90%
Conveyor C to conveyors D1, D2	FH-012	2,300	**DS/E	90%
Railcar to rail unloading hopper	FH-013	2,300	DS/E	95%
Rail unloading hopper to conveyor L	FH-014	2,300	**DS/E	95%
Conveyor L to conveyors D1, D2	FH-015	2,300	**DS/E	95%
Conveyor D1 to conveyor M1	FH-016	2,300	**DS/E	90%
Conveyor D2 to conveyor M2	FH-017	2,300	**DS/E	90%
Conveyor M1 to conveyor E1	FH-018	2,300	**DS/E	90%
Conveyor M2 to conveyor E2	FH-019	2,300	**DS/E	90%
Conveyor E1 to fuel storage pile	FH-020	2,300	DS	70%
Conveyor E2 to fuel storage pile	FH-021	2,300	DS	70%
Fuel storage pile	FH-022/023 a & b	NA	DS	50%
Dozer operations of storage piles	FH-044	NA	DS	50%
Truck unloading - auxiliary	AH-001	400	DS	85%
Storage pile	AH-002	400	DS/E	90%
Truck dump to flux storage pile	OMH-001	NA	DS	85%
Flux storage pile maintenance	OMH-002	NA	DS	50%
Flux storage pile	OMH-003	NA	DS	50%
Conveyor S to conveyor D1/D2	OMH-004	2300	DS/E	90%
Underground reclaim system to conveyors	OMH-005	2300	DS/E	90%

Notes: "DS" means dust suppressant. "E" means enclosure. "NA" means not applicable. The double asterisk (**) identifies the dust suppressant application point.

{Permitting Note: The above activities are regulated under the following: Rule 62-296.711, F.A.C. (Materials Handling, Sizing, Screening, Crushing and Grinding Operation); and Rule 62-296.700, F.A.C. (Reasonably Available Control Technology (RACT) for Particulate Matter). The existing fuel yard equipment previously served F. J. Gannon Station Units 1 through 6. The coal-fired boilers are permanently shut down.}

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

B.1 Permitted Capacity: Coal throughput for this facility shall not exceed 2.85 million tons in any 12 consecutive months. [Rules 62-4.160(2), 62-210.200 (PTE), and 62-212.400(2)(a)2, F.A.C.; Permit No. 0570040-006-AC]

B.2 Hours of Operation. This emissions unit is allowed to operate continuously (8760 hours per year). [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

CONTROL TECHNIQUES

B.3 Control Techniques: Water sprays or chemical wetting agents and stabilizers are acceptable methods to be used on coal storage piles as necessary to maintain an opacity of less than or equal to 5%. Other appropriate methods may be applied to maintain this opacity, after they are approved by the Department. Facilities that cause frequent, valid complaints may be required by the Compliance Authority to take these or other reasonable precautions. In determining what constitutes reasonable precautions for a particular source, the Compliance Authority shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice. [Permit Nos. 0570040-006-AC and 0570040-010-AC]

B.4 Application of Dust Suppressants: Dust suppressants shall be applied to the fuel either prior to or at the time of delivery and at all emission points as specified in Table B-1 of this subsection to control fugitive particulate matter emissions and maintain an opacity of less than or equal to 5%. For the application of dust suppressants prior to delivery, the permittee shall keep monthly records of: 1) the amount of dust suppressant applied for each type and amount of coal delivered, and 2) the type of dust suppressant used (e.g., MSD sheets, product name). [Permit No. 0570040-006-AC]

EMISSION LIMITATIONS AND STANDARDS

B.5 Visible Emissions. Visible emissions generated by fugitive or unconfined particulate matter from fuel handling systems and storage shall not exceed 5% opacity. *{Permitting note: The averaging time for this condition is based on the specified averaging time of the applicable test method, unless otherwise specified in this permit.}* [Rule 62-296.711(2)(a), F.A.C.; Permit No. AC29-152987]

TEST METHODS AND PROCEDURES

Visible Emissions: A thirty (30) minute visible emissions test shall be performed on the following material transfer operations during each federal fiscal year (October 1 - September 30):

1. The clamshell to the hopper;
2. The railcar to the hopper; and
3. Either conveyor E1 or E2 to their respective stockpiles where the initial free fall is at least 30 feet.

The test method for visible emissions shall be determined using EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C. [Rules 62-204.800, 62-297.310(4)(a)2, 62-297.310(7)(a)4, F.A.C.; Permit No. 0570040-006-AC]

MONITORING OF OPERATIONS

B.6 Proper Maintenance: All controls associated with the transfer points (i.e., the grab buckets, the windshield, the enclosures and the wet spray systems) shall be maintained to the extent that the capture efficiencies credited will be achieved. [Rule 62-4.070(3), F.A.C.; Permit No. AO29-216480]

B.7 Operation and Maintenance Plan for Particulate Matter Control

a. Process Parameters

1. Operation Schedule: 8760 hours per year
2. Equipment Data

   Conveyor Hoods: Corrugated Aluminum

   Transfer Point Enclosures: Carbon Steel
3. Manufacturer of Wet Dust Suppression Equipment: Benetech

b. Inspection and Maintenance Procedures: The fuel yard particulate matter control equipment shall receive regular preventative maintenance as follows:

1. Conveyor Enclosures
   - Daily random visual inspections of conveyor hoods.
   - Daily random visual inspection of the transfer points chute work
2. Dust Suppression System
   - Quarterly inspection of system for water leaks.
   - Quarterly inspection of spray nozzles.

   The pumps, tanks, etc., that make-up the dust suppression system undergo normal maintenance including lubrication, flushing, and draining.

[Rule 62-296.700, F.A.C.]

RECORDKEEPING AND REPORTING REQUIREMENTS

B.8 Testing Rates: All compliance testing shall be conducted during normal operation and at the maximum material (including limestone or iron ore where applicable) transfer rate attainable during the test period. Actual material handling rates will be determined using the totalizer readings obtained from scales located on C, L, and S conveyors. The readings from these scales will be recorded at the start and finish of the visible emissions test. The difference between the values recorded divided by the test duration will be the values used to represent the material handling rates. Alternatively, values from the circular chart recorders located in the coalfield control room will be used in the event a problem with a scale totalizer arises. The test result shall indicate if iron ore has been included in the corresponding material transfer rate. Failure to include the actual process or production rate in the results may invalidate the test. [Rule 62-4.070(3), F.A.C.; Permit No. AO29-216480]

B.9 O&M Records: Records of inspections, maintenance, and performance parameters shall be retained for a minimum of five years and shall be made available to the Compliance Authority upon request. [Rules 62-213.440(1)(b)2.b and 62-296.700(6)(e), F.A.C.]

B.10 Common Compliance Testing Requirements: Appendix CT of this permit identifies other compliance testing requirements commonly applicable to the emissions units in this subsection. These include the following requirements: Rule 297.310(7)(a)9, F.A.C. (Test Notification); Rule 62-297.310(5), F.A.C. (Determination of Process Variables); Rule 62-297.310(8), F.A.C. (Test Reports); and Rule 62-297.310(7), F.A.C. (Special Compliance Tests).

[Florida Administrative Code]

Plant Operated By: Tampa Electric Company
ORIS Code No. 0646

Subsection A. Phase II, Acid Rain, New Units.

The emissions units listed below are subject to Phase II of the federal Acid Rain Program as new units.

EU No.	Description
020	Bayside Unit CT-1A, Combined Cycle Gas Turbine
021	Bayside Unit CT-1B, Combined Cycle Gas Turbine
022	Bayside Unit CT-1C, Combined Cycle Gas Turbine
023	Bayside Unit CT-2A, Combined Cycle Gas Turbine
024	Bayside Unit CT-2B, Combined Cycle Gas Turbine
025	Bayside Unit CT-2C, Combined Cycle Gas Turbine
026	Bayside Unit CT-2D, Combined Cycle Gas Turbine

{Permitting Note: In accordance with the Consent Final Judgment (DEP vs. TECO) dated December 6, 1999 and the Consent Decree (U.S. vs. TECO) dated February 29, 2000, coal-fired Emissions Units 001 through 006 are permanently shut down.}

A.1 Phase II Acid Rain Permit: The Phase II permit application submitted for this facility, as approved by the Department, is a part of this permit (included as an Attachment). The owners and operators of these Phase II acid rain units must comply with the standard requirements and special provisions set forth in the Title V renewal application [DEP Form No. 62-210.900(1)(a)] dated 07/02/04. [Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2 SO_2 Allowance Allocations: Sulfur dioxide (SO_2) allowance allocations for each Acid Rain unit are as follows:

EU No.	EPA ID	SO_2 allowances, under Table 2 or 3 of 40 CFR 73				
		2005	2006	2007	2008	2009
020	CT1A	0*	0*	0*	0*	0*
021	CT1B	0*	0*	0*	0*	0*
022	CT1C	0*	0*	0*	0*	0*
023	CT2A	0*	0*	0*	0*	0*
024	CT2B	0*	0*	0*	0*	0*
025	CT2C	0*	0*	0*	0*	0*
026	CT2D	0*	0*	0*	0*	0*

* The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the U.S. EPA under Table 2 or 3 of 40 CFR 73.

A.3 Emission Allowances: Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a

permit revision pursuant to Rule 62-213.400(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c)1, 2 and 3, F.A.C.]

A.4 Statement of Compliance: The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. *{Permitting Note: See condition No. 51 in Appendix TV-4, Title V Conditions.}* [Rule 62-214.420(11), F.A.C.]

A.5 Fast-Track Revisions of Acid Rain Parts: Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, Fast-Track Revisions of Acid Rain Parts. [Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.6 Comments, Notes and Justifications: None.

Subsection B. Phase II, Acid Rain, Retired Units.

The emissions units listed below are subject to Phase II of the federal Acid Rain Program as retired units.

EU No.	Description
001	Fossil Fuel Fired Steam Generator, Gannon Unit 1 - PERMANENTLY RETIRED
002	Fossil Fuel Fired Steam Generator, Gannon Unit 2 - PERMANENTLY RETIRED
003	Fossil Fuel Fired Steam Generator, Gannon Unit 3 - PERMANENTLY RETIRED
004	Fossil Fuel Fired Steam Generator, Gannon Unit 4 - PERMANENTLY RETIRED
005	Fossil Fuel Fired Steam Generator, Gannon Unit 5 - PERMANENTLY RETIRED
006	Fossil Fuel Fired Steam Generator, Gannon Unit 6 - PERMANENTLY RETIRED

B.1. Retired Unit Exemption: The Retired Unit Exemption form submitted for this facility constitutes the Acid Rain Part application pursuant to 40 CFR 72.8 and is a part of this permit. The owners and operators of the acid rain units shall comply with the standard requirements and special provisions set forth in DEP Form No. 62-210.900(1)(a)3., effective April 16, 2001, signed by the Designated Representative on March 31, 2004. The units are subject to the following: 40 CFR 72.1 which requires the units to have an Acid Rain Part as part of its Title V permit; 40 CFR 72.2 which provides associated definitions; 40 CFR 72.3 which provides measurements, abbreviations, and acronyms; 40 CFR 72.4 which provides the federal authority of the Administrator; 40 CFR 72.5 which provides the authority of the states; 40 CFR 72.6 which makes the boilers Phase II units; 40 CFR 72.10 which gives the public access to information about the units; and 40 CFR 72.13 which incorporates certain ASTM methods into 40 CFR Part 72.

[Chapter 62-213, F.A.C. and Rule 62-214.340, F.A.C.]

B.2. SO_2 Allowance Allocations: Sulfur dioxide (SO_2) allowance allocations for these Acid Rain units are as follows:

EU No.	EPA ID	SO_2 allowances, under Table 2 of 40 CFR 73				
		2005	2006	2007	2008	2009
001	GB01	3842*	3842*	3842*	3842*	3842*
002	GB02	4425*	4425*	4425*	4425*	4425*
003	GB03	5664*	5664*	5664*	5664*	5664*
004	GB04	6223*	6223*	6223*	6223*	6223*
005	GB05	6537*	6537*	6537*	6537*	6537*
006	GB06	10,081*	10,081*	10,081*	10,081*	10,081*

* The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the U.S. EPA under Table 2 of 40 CFR 73.

Pursuant to the Consent Decree (U.S. EPA vs. TECO), there are additional restrictions on the sulfur dioxide allowance allocations and the use of these allocations. Provision 46 of the Consent Decree (U.S. EPA vs. TECO) is provided below for convenience.

"Exclusion of Certain Emission Allowances. For any and all actions taken by Tampa Electric pursuant to the terms of this Consent Decree, including but not limited to upgrading of ESPs and scrubbers, installation of NOx controls, Re-Powering, and Shutdown, Tampa Electric shall not use or sell any resulting NOx or SO_2 emission allowances or credits in any emission trading or marketing program of any kind; provided, however, that:

A. SO_2 credits allocated to Tampa Electric by the Administrator of EPA under the Act, due to the Re-Powering or Shutdown of Gannon, may be retained by Tampa Electric during the year in which they are allocated, but only for Tampa Electric's own use in meeting any acid rain requirement imposed under the Act. For any such allowances not used by Tampa Electric for this purpose by June 30 of the following calendar year, Tampa Electric shall not use, sell, trade, or otherwise transfer these allowances for its benefit or the benefit of a third party unless such a transfer would result in the retiring of such allowances without their ever being used.

B. If Tampa Electric decides to Re-Power any Unit at Big Bend, then Tampa Electric shall be entitled to retain for any purpose under law the difference between the emission allowances that would have resulted from installing BACT-level NOx and SO_2 controls at the existing coal-fired Unit and the emission allowances that result from Re-Powering that Unit. Before Tampa Electric uses any allowances within the scope of this Subparagraph, Tampa Electric shall submit the calculation of the net emission allowances for approval by the United States.

C. Nothing in this Consent Decree shall preclude Tampa Electric from using or selling emission allowances arising from Tampa Electric's activities occurring prior to December 31, 1999, or Tampa Electric's activities after that date that are not related to actions required of Tampa Electric under this Consent Decree. The United States and Tampa Electric agree that the operation of the SO_2 scrubber serving Big Bend Units 1 and 2 meets the requirements of this Subparagraph, and that emission allowances resulting from the operation of this scrubber shall not be treated as an activity related to or required under this Consent Decree."

B.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.440(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c)1, 2, and 3, F.A.C.]

B.4. Date of Permanent Retirement: The designated representative of the acid rain units applied for an exemption from the requirements of the Federal Acid Rain Program by submitting a completed and signed "Retired Unit Exemption" form (DEP Form No. 62-210.900(1)(a)3., F.A.C., attached) to the Department. The dates of permanent retirement are: GB01 (04/16/03); GB02 (04/15/03); GB03 (11/01/03); GB04 (10/12/03); GB05 (01/30/03); and GB06 (09/30/03). [Rule 62-214.340(2), F.A.C.; and, 40 CFR 72.8.]

B.5. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within sixty (60) days after the end of the calendar year. *{See Condition No. 51 in Appendix TV-4, Title V Conditions.}* [Rule 62-214.420(11), F.A.C.]

B.6. Applicable Requirements: Where an applicable requirement of the Act is more stringent than applicable regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator. [40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, F.A.C., Definitions – Applicable Requirements.]

B.7. Comments: Comments, notes, and justifications: None.

Tampa Electric Company
H. L. Culbreath Bayside Power Station
Title V Air Operation Permit No. 0570040-023-AV

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

Abbreviations and Acronyms

ARMS	-	Air Resource Management System (state database)
BACT	-	Best Available Control Technology
CFR	-	Code of Federal Regulations
DEP	-	State of Florida, Department of Environmental Protection
DARM	-	Division of Air Resource Management
EPA	-	United States Environmental Protection Agency
F.A.C.	-	Florida Administrative Code
F.S.	-	Florida Statute
ISO	-	International Standards Organization (288° K, 60% relative humidity, and 101.3 kPa pressure)
MMBtu	-	million British Thermal Units
MW	-	Megawatt

Regulatory Citations

Example: [40 CFR 60.334]

Where: "40" refers to Title 40 of the Code of Federal Regulations (CFR)
"60" refers to Part 60
"334" refers to the section (§ 60.334) regarding the monitoring of operations from gas turbines

Example: [Rule 62-213, F.A.C.]

Where: "62" refers to Title 62 of the Florida Administrative Code (F.A.C.)
"213" refers to Chapter 62-213 regarding Title V sources
"205" refers to Rule 62-213.205 regarding Title V annual fees

Facility Identification (ID) Numbers

Example: Facility ID No. 1050221 (Tracking number used in the state database.)

Where: "105" is a unique 3-digit number code identifying that the facility is located in Polk County
"0221" is a unique 4-digit number code identifying the specific facility in the state database

Permit and Certification Numbers

Example: Air Permit No. 1050221-001-AC or 1050221-002-AV (New Permit Numbers)

Where: "1050221" represents the facility ID number
"001 or 002" are unique 3-digit project numbers assigned by the state database
"AC" means Air Construction Permit and "AV" means Title V Air Operation Permit

Example: Air Permit No. AC50-123456 or Air Permit No. AO50-123456 (Old Permit Numbers)

Where: "AC" means Air Construction Permit and "AO" means Air Operation Permit
"123456" is the sequential permit number

Example: Air Permit No. PSD-FL-185

Where: "PSD" means a an air construction permit for the Prevention of Significant Deterioration
"FL" means that it was issued in Florida
"185" is the sequential permit number

Example: Certification No. PA95-01

Where: "PA" means a certification based on the Power Plant Siting Act
"95" means that it was issued in 1995
"01" is the sequential certification number for that year

Attached is the federal Acid Rain Part Application submitted as part of the renewal application for a Title V air operation permit, which was originally received by the Department on July 2, 2004. The Retired Unit Exemption Forms were signed by the designated representative on March 31, 2004. The Acid Rain Part Application was originally signed on June 30, 2004. The Acid Rain Part Application was later updated and signed on November 5, 2004. These documents are attached as part of this permit for completeness, but are distributed to the permittee only with the Final Permit. Other persons requesting copies of these documents shall be provided one copy when requested or otherwise appropriate.

Emissions Standards for Bayside Units 1 – 2 (Emissions Units 020 through 026)

Each emissions unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter, and associated support equipment. Each unit Natural gas is the exclusive fuel. At a compressor inlet air temperature of 59° F and firing 1842 MMBtu (HHV) per hour of natural gas, each unit produces a nominal 169 MW of shaft-driven electricity. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,000 acfm at 220° F.

Pollutant	Controls and Standards [a]
Standards based on emissions performance tests at permitted capacity and an inlet temperature of 59° F:	
Ammonia	*Standard*: 5 ppmvd @ 15% O_2 [b]
CO (BACT)	*Control*: DLN combustion technology and exclusive firing of natural gas *Standard*: 7.8 ppmvd @ 15% O_2 *Standard*: 28.7 lb/hour
NOx	*Controls*: SCR with DLN combustion technology and exclusive firing of natural gas *Standard*: 3.5 ppmvd @ 15% O_2 *Standard*: 23.1 lb/hour
PM/PM_{10} (BACT)	*Controls*: DLN combustion technology and exclusive firing of natural gas *Standard*: 10% opacity, 6-minute average *Comments*: The CO CEMS standard serves as a continuous indicator of efficient combustion. The estimated maximum emissions are 12 lb/hour (front-half catch only).
SAM/SO_2	*Standard*: Exclusive firing of natural gas (< 2 grains per 100 SCF, 12 month rolling average)
VOC (BACT)	*Controls*: DLN combustion technology and exclusive firing of natural gas *Comments*: The CO CEMS standard serves as a continuous indicator of efficient combustion. The estimated maximum emissions are 3 lb/hour (1.3 ppmvd @ 15% O_2).
Standards based on CEMS data:	
CO (BACT)	*Control*: DLN combustion technology and exclusive firing of natural gas *Standard*: 9.0 ppmvd @ 15% O_2, 24-hour block average
NOx	*Controls*: SCR with DLN combustion technology and exclusive firing of natural gas *Standard*: 3.5 ppmvd @ 15% O_2, 24-hour block average

Notes:

a. "BACT" means Best Available Control Technology. "SCR" means selective catalytic reduction system. "DLN" means dry low-NOx combustion technology.

b. If the tested ammonia slip rate exceeds 5 ppmvd corrected to 15% oxygen during the required annual test, the permittee shall begin testing and reporting the ammonia slip for each subsequent calendar quarter. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, the permittee shall take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen. The permittee shall test and demonstrate that the ammonia slip is less than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

A detailed description of each BACT evaluation is presented in the Technical Evaluation and Preliminary Determination. Any changes are noted in the Department's Final Determination issued simultaneously with the final permit.

Final BACT Determinations

Actual emissions of NOx and SO_2 from the re-powered plant will decrease due to the shutdown of existing coal-fired units. Therefore, the project nets out of PSD for NOx and SO_2 emissions. However, each gas turbine is required to fire natural gas as the primary fuel and to incorporate an SCR system as a result of the DEP/TEC Consent Final Judgment and the EPA/TEC Consent Decree. The gas turbines are subject to the acid rain requirements, which require a continuous emissions monitoring system (CEMS) for NOx emissions. The NOx CEMS will also be used to demonstrate compliance with the specified permit standards.

The project did result in significant net actual emissions increases of carbon monoxide (CO) and volatile organic compounds (VOC). Based on an interpretation by EPA Region 4, emissions of particulate matter (PM/PM10) would also be significant if BACT-level controls had previously been installed on the existing Gannon Units. For CO, PM/PM10, and VOC emissions, the Department determines that the efficient combustion of pipeline-quality natural gas and good operating practices represent BACT for the combined cycle units. In addition to the control requirements, the CO, PM/PM10, and VOC emissions standards specified in the permit and summarized in the above table represent the determination of Best Available Control Technology (BACT). A continuous emission monitoring system (CEMS) is required to demonstrate continuous compliance with the CO standards. The CO CEMS will also serve as a continuous indicator of efficient combustion to minimize PM and VOC emissions. The Department's detailed technical review and rationale for the determinations of Best Available Control Technology (BACT) are presented in Technical Evaluation and Preliminary Determination issued with the draft PSD permit package.

Mass Emission Rate Summary

The following table summarizes the hourly mass emission rates (lb/hour) at various the compressor inlet temperatures.

Pollutant	Compressor Inlet Temperature	Mass Emission Rate lb/hour
CO	18° F	31.1
	35° F	30.0
	59° F	28.7
	72° F	27.8
	93° F	26.9
NOx	18° F	24.7
	35° F	23.8
	59° F	23.1
	72° F	22.6
	93° F	21.9
PM/PM10	18° F	11.5
	35° F	11.4
	59° F	11.3
	72° F	11.3
	93° F	11.2
VOC	18° F	3.0
	35° F	3.0
	59° F	2.8
	72° F	2.7
	93° F	2.7

Notes:

- This table represents the mass emission rates for the General Electric Model PG7241(FA) gas turbine (combined cycle) firing natural gas with a selective catalytic reduction system to reduce NOx emissions.
- NOx emission rates are reported as NO_2 and are based on control with DLN combustion and an SCR system.
- PM emission rates are based on EPA Method 5 (front-half catch only).
- VOC emission rates are measure as methane.

On October 4, 2000, the United States and Tampa Electric Company entered into a settlement agreement (Consent Decree, Civil Action No. 99-2524). In May of 2001, this agreement was amended. These documents are attached as part of this permit for completeness, but are distributed to the permittee only with the Final Permit. Other persons requesting copies of these documents shall be provided one copy when requested or otherwise appropriate.

On December 7, 1999, the Florida Department of Environmental Protection and the Tampa Electric Company entered into a settlement agreement (Consent Final Judgment, Case No. 99-009737. This document is attached as part of this permit for completeness, but is distributed to the permittee only with the Final Permit. Other persons requesting copies of this document shall be provided one copy when requested or otherwise appropriate.

Unless otherwise specified in the permit, the following testing requirements apply to each emissions unit as necessary.

62-297.310 General Compliance Test Requirements.

The focal point of a compliance test is the stack or duct which vents process and/or combustion gases and air pollutants from an emissions unit into the ambient air.

(1) Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20% below the allowable emission limiting standard.

[Rule 62-297.310(1), F.A.C.]

(2) Operating Rate During Testing. Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operating at permitted capacity as defined below. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

(a) *Combustion Turbines.* (Reserved)

(b) *All Other Sources.* Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit.

[Rule 62-297.310(2), F.A.C.]

(3) Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

(4) Applicable Test Procedures.

(a) *Required Sampling Time.*

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c. The minimum observation period for opacity tests conducted by employees or agents of the

Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) *Minimum Sample Volume.* Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) *Required Flow Rate Range.* For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in *Table 297.310-1.*

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

TABLE 62-297.310-1: TEST EQUIPMENT CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in Glass Thermometer	Annually	ASTM Hg in glass reference thermometer or equivalent or thermometric points.	+/- 2%
Bimetallic Thermometer	Quarterly	Calibrated liquid in glass thermometer.	5°F
Thermocouple	Annually	ASTM Hg in glass reference thermometer; NBS calibrated reference and potentiometer.	5°F
Barometer	Monthly	Hg barometer or NOAA station.	+/- 1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube.	See EPA Method 2, Figures 2-2 and 2-3.
Probes Nozzles	Before each test or when nicked, dented, or corroded.	Micrometer	+/- 0.001" mean of at least 3 readings. Maximum allowed deviation between readings is 0.004".
Dry Gas Meter and Orifice Meter	1. Full scale: initially when received; annually when 5% change observed. 2. One point: semi-annually 3. Check after each test series.	Spirometer or calibrated wet test or dry gas test meter. Comparison check.	2% 5%

[Rule 62-297.310(4, F.A.C.]

(5) Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables,

including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

(6) Required Stack Sampling Facilities. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

(a) *Permanent Test Facilities.* The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities. (b) Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

(c) *Sampling Ports.*

1. All sampling ports shall have a minimum inside diameter of 3 inches.
2. The ports shall be capable of being sealed when not in use.
3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.
4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.
5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d) *Work Platforms.*

1. Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.
2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.
3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.
4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e) *Access to Work Platform.*

1. Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.
2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f) *Electrical Power.*

1. A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet

of each sampling port.

2. If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

(g) *Sampling Equipment Support.*

1. A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

   a. The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

   b. A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

   c. The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

3. When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

[Rule 62-297.310(6), F.A.C.]

(7) Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) *General Compliance Testing.*

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

   a. Visible emissions, if there is an applicable standard;

   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

   c. Each NESHAP pollutant, if there is an applicable emission standard.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

(b) *Special Compliance Tests.* When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

[Rule 62-297.310(7), F.A.C.]

(8) Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

(9) Stack or Duct: The terms stack and duct are used interchangeably in this rule. [Rule 62-297.310(9), F.A.C.]

APPENDIX I. LIST OF INSIGNIFICANT EMISSIONS UNITS AND/OR ACTIVITIES

The emissions units and activities listed in Rule 62-210.300(3)(a), F.A.C. (Categorical Exemptions) or those that meet the criteria specified in Rule 62-210.300(3)(b)1, F.A.C. (Generic Emissions Unit Exemption) are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C. provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1, F.A.C. shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C. if they are contained within a Title V source. However, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1, F.A.C. if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

Based on the Title V renewal application received on July 2, 2004, the following emissions units and activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

1. Emergency diesel 600 kW generator.
2. Freshwater cooling tower.
3. Brazing, soldering or welding equipment.
4. Comfort heating units with a gross minimum heat output of less than 1 MMBtu/hour.
5. No. 2 and No. 6 fuel oil storage tanks.
6. No. 2 and No. 6 fuel oil truck unloading operations.
7. Fuel oil processing and treating equipment.
8. Laboratory equipment used exclusively for chemical or physical analyses.
9. Fire and safety equipment.
10. Turbine vapor extractors.
11. Non-halogenated solvent storage and cleaning operations.
12. Architectural (and equipment) maintenance painting.
13. 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:
    - Such operations are not subject to a volatile organic compound Reasonably Available Control Technology (RACT) requirement of Chapter 62-296, F.A.C.
    - The amount of coatings used shall include any solvents and thinners used in the process including those used for cleanup.
14. Surface coating operations utilizing only coatings containing 5.0 percent or less VOCs, by volume.
15. Degreasing units using heavier-than-air vapors exclusively, except any such unit using or emitting any substance classified as a hazardous air pollutant.
16. Internal combustion engines in boats, aircraft and vehicles used for transportation of passengers or freight.
17. Equipment used for steam cleaning.
18. Petroleum lubrication systems.

NSPS SUBPART GG REQUIREMENTS

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

Pursuant to 40 CFR 60.332, Standard for Nitrogen Oxides:

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

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

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

Where:

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

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

F = NOx emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

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

Fuel-bound nitrogen (percent by weight)	F (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: For natural 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" value provided by the applicant is approximately 10.0 for natural gas. The equivalent emission standard is 108 ppmvd @ 15% oxygen. The permit standards are more stringent than this requirement.}

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

Pursuant to 40 CFR 60.333, Standard for Sulfur Dioxide:

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

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

{Note: The permit specifies a much lower fuel sulfur content for natural gas.}

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:

(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. 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).

Department requirement: NOx CEMS data shall substitute for the above requirement because NOx monitoring is required to demonstrate compliance with the permit standards. NOx CEMS data 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.

Pursuant to 40 CFR 60.335, Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 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 pro-vided 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

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

{Note: This is consistent with guidance from EPA Region 4.}

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The permittee is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the specified NOx limits.

{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.

Department requirement: The permittee is allowed to make the initial compliance demonstration for NOx emissions using certified CEMS data, provided that compliance is 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 in the permit 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 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: The permit species sulfur monitoring methods.

(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.}

{Permitting Note: Appendix TV-4 (Title V Conditions) is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided one copy when requested or otherwise appropriate.}

{Note: This form is based on 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: Nitrogen Oxides (NOx) Carbon Monoxide (CO)

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer and Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Units Description: _____

Total source operating time in reporting period [a]: _____

Emission data summary [a]		CMS performance summary [a]	
1. Duration of Excess Emissions In Reporting Period Due To:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown		a. Monitor Equipment Malfunctions	
b. Control Equipment Problems		b. Non-Monitor Equipment Malfunctions	
c. Process Problems		c. Quality Assurance Calibration	
d. Other Known Causes		d. Other Known Causes	
e. Unknown Causes		e. Unknown Causes	
2. Total Duration of Excess Emissions		2. Total CMS Downtime	
3. [Total Duration of Excess Emissions] x (100%) [Total Source Operating Time] [b]		3. [Total CMS Downtime] x (100%) [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

[b] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes to CMS, process or controls during last 6 months. For each quarter, summarize the ammonia injection rates over various loads and the data excluded due to startups, shutdowns, and malfunctions.

I certify that the information contained in this report is true, accurate, and complete.

_____
Name

_____
Title

_____ _____
Signature *Date*

Retired Unit Exemption

For more information, see instructions and refer to Rule 62-214.340(2), F.A.C., and 40 CFR 72.8

This submission is: [X] New [ ] Revised

STEP 1
Identify the unit by plant name, State, ORIS code and unit ID#.

F.J. Gannon Station	Florida	0646	GN06
Plant Name	State	ORIS Code	Unit ID#

STEP 2
Identify the first full calendar year in which the unit meets (or will meet) the requirements of Rule 62-214.340(2)(a), F.A.C.

January 1, 2004.

STEP 3
Read the special provisions.

Special Provisions

(1) A unit exempt under Rule 62-214.340(2), F.A.C., shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B. If the unit is a Phase I unit, for each calendar year in Phase I, the designated representative of the unit shall submit a Phase I permit application in accordance with 40 CFR part 72 subparts C and D and an annual certification report in accordance with 40 CFR 72.90 through 72.92 and is subject to 40 CFR 72.95 and 72.96.
(2) A unit exempt under Rule 62-214.340(2), F.A.C., shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain part application under Rule 62-214.320, F.A.C., for the unit not less than 24 months prior to the date on which the unit is first to resume operation.
(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under Rule 62-214.340(2), F.A.C., shall comply with the requirements of Chapter 62-214, F.A.C., and the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
(4) For any period for which a unit is exempt under Rule 62-214.340(2), F.A.C., the unit is not an Acid Rain unit and is not eligible to be an opt-in source under 40 CFR part 74. As a non-Acid Rain Unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR part 70.
(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under Rule 62-214.340(2), F.A.C., shall retain at the source that includes the unit records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the EPA or the Department. The owners and operators bear the burden of proof that the unit is permanently retired.
(6) On the earlier of the following dates, a unit exempt under Rule 62-214.340(2), F.A.C., shall lose its exemption and become an Acid Rain Unit: (i) the date on which the designated representative submits an Acid Rain part application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain part application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under Rule 62-214.340(2), F.A.C., shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

STEP 4
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

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: Gregory M. Nelson	
Signature: Gregory M. Nelson	Date: 3/31/04

Retired Unit Exemption

For more information, see instructions and refer to Rule 62-214.340(2), F.A.C., and 40 CFR 72.8

This submission is: [X] New [ ] Revised

STEP 1
Identify the unit by plant name, State, ORIS code and unit ID#.

Plant Name	State	ORIS Code	Unit ID#
F.J. Gannon Station	Florida	0646	GN05

STEP 2
Identify the first full calendar year in which the unit meets (or will meet) the requirements of Rule 62-214.340(2)(a), F.A.C.

January 1, 2004.

STEP 3
Read the special provisions.

Special Provisions

(1) A unit exempt under Rule 62-214.340(2), F.A.C., shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B. If the unit is a Phase I unit, for each calendar year in Phase I, the designated representative of the unit shall submit a Phase I permit application in accordance with 40 CFR part 72 subparts C and D and an annual certification report in accordance with 40 CFR 72.90 through 72.92 and is subject to 40 CFR 72.95 and 72.96.
(2) A unit exempt under Rule 62-214.340(2), F.A.C., shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain part application under Rule 62-214.320, F.A.C., for the unit not less than 24 months prior to the date on which the unit is first to resume operation.
(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under Rule 62-214.340(2), F.A.C., shall comply with the requirements of Chapter 62-214, F.A.C., and the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
(4) For any period for which a unit is exempt under Rule 62-214.340(2), F.A.C., the unit is not an Acid Rain unit and is not eligible to be an opt-in source under 40 CFR part 74. As a non-Acid Rain Unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR part 70.
(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under Rule 62-214.340(2), F.A.C., shall retain at the source that includes the unit records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the EPA or the Department. The owners and operators bear the burden of proof that the unit is permanently retired.
(6) On the earlier of the following dates, a unit exempt under Rule 62-214.340(2), F.A.C., shall lose its exemption and become an Acid Rain Unit: (i) the date on which the designated representative submits an Acid Rain part application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain part application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under Rule 62-214.340(2), F.A.C., shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

STEP 4
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

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	Date
Gregory M. Nelson	
Signature: Gregory M. Nelson	3/31/04

Retired Unit Exemption

or more information, see instructions and refer to Rule 62-214.340(2), F.A.C., and 40 CFR 72.8

This submission is: [X] New [ ] Revised

STEP 1
Identify the unit by plant name, State, ORIS code and unit ID#.

F.J. Gannon Station	Florida	0646	GN03
Plant Name	State	ORIS Code	Unit ID#

STEP 2
Identify the first full calendar year in which the unit meets (or will meet) the requirements of Rule 62-214.340(2)(a), F.A.C.

January 1, 2004

STEP 3
Read the special provisions.

Special Provisions

(1) A unit exempt under Rule 62-214.340(2), F.A.C., shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B.

- If the unit is a Phase I unit, for each calendar year in Phase I, the designated representative of the unit shall submit a Phase I permit application in accordance with 40 CFR part 72 subparts C and D and an annual certification report in accordance with 40 CFR 72.90 through 72.92 and is subject to 40 CFR 72.95 and 72.96.

(2) A unit exempt under Rule 62-214.340(2), F.A.C., shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain part application under Rule 62-214.320, F.A.C., for the unit not less than 24 months prior to the date on which the unit is first to resume operation.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under Rule 62-214.340(2), F.A.C., shall comply with the requirements of Chapter 62-214, F.A.C., and the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) For any period for which a unit is exempt under Rule 62-214.340(2), F.A.C., the unit is not an Acid Rain unit and is not eligible to be an opt-in source under 40 CFR part 74. As a non-Acid Rain Unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR part 70.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under Rule 62-214.340(2), F.A.C., shall retain at the source that includes the unit records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the EPA or the Department. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) On the earlier of the following dates, a unit exempt under Rule 62-214.340(2), F.A.C., shall lose its exemption and become an Acid Rain Unit: (i) the date on which the designated representative submits an Acid Rain part application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain part application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under Rule 62-214.340(2), F.A.C., shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

STEP 4
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

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Name: Gregory M. Nelson	
Signature: Gregory M Nelson	Date:

Retired Unit Exemption

For more information, see instructions and refer to Rule 62-214.340(2), F.A.C., and 40 CFR 72.8

This submission is: [X] New [ ] Revised

STEP 1
Identify the unit by plant name, State, ORIS code and unit ID#.

Plant Name	State	ORIS Code	Unit ID#
F.J. Gannon Station	Florida	0646	GN04

STEP 2
Identify the first full calendar year in which the unit meets (or will meet) the requirements of Rule 62-214.340(2)(a), F.A.C.

January 1, 2004.

STEP 3
Read the special provisions.

Special Provisions

(1) A unit exempt under Rule 62-214.340(2), F.A.C., shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B. If the unit is a Phase I unit, for each calendar year in Phase I, the designated representative of the unit shall submit a Phase I permit application in accordance with 40 CFR part 72 subparts C and D and an annual certification report in accordance with 40 CFR 72.90 through 72.92 and is subject to 40 CFR 72.95 and 72.96.
(2) A unit exempt under Rule 62-214.340(2), F.A.C., shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain part application under Rule 62-214.320, F.A.C., for the unit not less than 24 months prior to the date on which the unit is first to resume operation.
(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under Rule 62-214.340(2), F.A.C., shall comply with the requirements of Chapter 62-214, F.A.C., and the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
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(6) On the earlier of the following dates, a unit exempt under Rule 62-214.340(2), F.A.C., shall lose its exemption and become an Acid Rain Unit: (i) the date on which the designated representative submits an Acid Rain part application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain part application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under Rule 62-214.340(2), F.A.C., shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

STEP 4
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

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	
Gregory M. Nelson	
Signature: Gregory M. Nelson	Date: 3/31/04

Acid Rain Program
Instructions for
Acid Rain Part Application
(40 CFR 72.30 - 72.31 and Rule 62-214.320, F.A.C.)

The Acid Rain Program requires the designated representative to submit an Acid Rain part application for each source with an Acid Rain unit. A complete Certificate of Representation must be received by EPA before the part application is submitted to the title V permitting authority. A complete Acid Rain part application, once submitted, is binding on the owners and operators of the Acid Rain source and is enforceable in the absence of an Acid Rain part until the title V permitting authority either issues an Acid Rain part to the source or disapproves the application.

Please type or print. The alternate designated representative may sign in lieu of the designated representative. If assistance is needed, contact the title V permitting authority.

STEP 1 Use the plant name and ORIS Code listed on the Certificate of Representation for the plant. An ORIS code is a 4 digit number assigned by the Energy Information Agency (EIA) at the U.S. Department of Energy to power plants owned by utilities. If the plant is not owned by a utility but has a 5 digit facility code (also assigned by EIA), use the facility code. If no code has been assigned or if there is uncertainty regarding what the code number is, contact EIA at (202) 287-1730 (for ORIS codes), or (202) 287-1927 (for facility codes).

STEP 2 For column "a," identify each Acid Rain unit at the Acid Rain source by providing the appropriate unit identification numbers, consistent with the unit identification numbers entered on the Certificate of Representation and with unit identification numbers used in reporting to DOE and/or EIA. For new units without identification numbers, owners and operators may assign such numbers consistent with EIA and DOE requirements.

For columns "c" and "d," enter the commence operation date(s) and monitor certification deadline(s) for new units in accordance with 40 CFR 72.2 and 75.4, respectively.

Submission Deadlines

For new units, an initial Acid Rain part application must be submitted to the title V permitting authority 24 months before the date the unit commences operation. Acid rain part renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a title V permit, or such longer time as provided for under the title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form to the appropriate title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional acid rain contact, or call EPA's Acid Rain Hotline at (202) 564-9620.

Acid Rain Part Application

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

This submission is: ☒ New ☐ Revised

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

Plant Name **Bayside Power Station** State **FL** ORIS Code **7873**

STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a." For new units, enter the requested information in columns "c" and "d."

a Unit ID#	b Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	c New Units Commence Operation Date	d New Units Monitor Certification Deadline
GN1	Yes		
GN2	Yes		
GN3	Yes		
GN4	Yes		
GN5	Yes		
GN6	Yes		
CT1A	Yes	03/01/03	06/01/03
CT1B	Yes	03/01/03	06/01/03
CT1C	Yes	03/01/03	06/01/03
CT2A	Yes	01/01/04	04/01/04
CT2B	Yes	01/01/04	04/01/04
CT2C	Yes	01/01/04	04/01/04
CT2D	Yes	01/01/04	04/01/04

Bayside Power Station
Plant Name (from Step 1)

STEP 3
Read the standard requirements

Acid Rain Part Requirements

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the Department determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain part;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the Department; and
(ii) Have an Acid Rein 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)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), 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) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain part application, the Acid Rain part, or an exemption under 40 CFR 72.7 or 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 EPA or the Department:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Bayside Power Station
Plant Name (from Step 1)

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

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

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7or 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.

STEP 4

Read the certification statement, sign, and date

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	Gregory M. Nelson	
Signature	Gregory M. Nelson	Date 11/5/04

TAMPA ELECTRIC

March 31, 2004

U.S. Environmental Protection Agency
Acid Rain Program (6204J)
Attn: Retired Unit Exemption
401 M St., SW
Washington, D.C. 20460

Via FedEx
Airbill No. 7918 0879 7947

Mr. Al Linero
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7905 9593 6143

Re: Tampa Electric Company
Retired Unit Exemption
F.J. Gannon Station
ORIS Plant Code 000646
AIRS 0570040, EPA ID: GN01-GN06

Dear Sir or Madam:

Per Tampa Electric Company's (TEC) conversation with Ms. Laurel DeSantis (USEPA) on March 29, 2004, the six oil fired boilers at TEC's F.J. Gannon Station were shutdown as follows:

GN05-01/30/03
GN02-04/15/03
GN01-04/16/03
GN06-09/30/03
GN04-10/12/03
GN03-11/01/03

Please find enclosed retired unit exemption forms for EPA ID: GN01- GN06. These units were retired as of January 1, 2004, per the Acid Rain provisions governing the retired unit exemption under Rule 62-214.340(2), F.A.C.

TAMPA ELECTRIC COMPANY
P. O. BOX 111 TAMPA, FL 33601-0111

(813) 228-4111

AN EQUAL OPPORTUNITY COMPANY
HTTP://WWW.TAMPAELECTRIC.COM

CUSTOMER SERVICE:
HILLSBOROUGH COUNTY (813) 223-0800
OUTSIDE HILLSBOROUGH COUNTY 1 (888) 223-0800

If you have any questions, please call Ms. Greer Briggs or me at (813) 228-4302.

Sincerely,

Gregory M. Nelson
Director
Environmental, Health & Safety

EA/bmr/GMB1669

Enclosure

c Mr. Jerry Campbell, EPCHC
Ms. Trina Vielhauer, FDEP
Mr. Jerry Kissel - FDEP SW

Retired Unit Exemption

For more information, see instructions and refer to Rule 62-214.340(2), F.A.C., and 40 CFR 72.8

This submission is: [X] New [ ] Revised

STEP 1
Identify the unit by plant name, State, ORIS code and unit ID#.

F.J. Gannon Station	Florida	0646	GN01
Plant Name	State	ORIS Code	Unit ID#

STEP 2
Identify the first full calendar year in which the unit meets (or will meet) the requirements of Rule 62-214.340(2)(a), F.A.C.

January 1, 2004.

STEP 3
Read the special provisions.

Special Provisions

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STEP 4
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

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Name: Gregory M. Nelson	
Signature: Gregory M. Nelson	Date: 3/31/04

Retired Unit Exemption

For more information, see instructions and refer to Rule 62-214.340(2), F.A.C., and 40 CFR 72.8

This submission is: [X] New [ ] Revised

STEP 1
Identify the unit by plant name, State, ORIS code and unit ID#.

Plant Name	State	ORIS Code	Unit ID#
F.J. Gannon Station	Florida	0646	GN02

STEP 2
Identify the first full calendar year in which the unit meets (or will meet) the requirements of Rule 62-214.340(2)(a), F.A.C.

January 1, 2004

STEP 3
Read the special provisions.

Special Provisions

(1) A unit exempt under Rule 62-214.340(2), F.A.C., shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B. If the unit is a Phase I unit, for each calendar year in Phase I, the designated representative of the unit shall submit a Phase I permit application in accordance with 40 CFR part 72 subparts C and D and an annual certification report in accordance with 40 CFR 72.90 through 72.92 and is subject to 40 CFR 72.95 and 72.96.
(2) A unit exempt under Rule 62-214.340(2), F.A.C., shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain part application under Rule 62-214.320, F.A.C., for the unit not less than 24 months prior to the date on which the unit is first to resume operation.
(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under Rule 62-214.340(2), F.A.C., shall comply with the requirements of Chapter 62-214, F.A.C., and the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.
(4) For any period for which a unit is exempt under Rule 62-214.340(2), F.A.C., the unit is not an Acid Rain unit and is not eligible to be an opt-in source under 40 CFR part 74. As a non-Acid Rain Unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR part 70.
(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under Rule 62-214.340(2), F.A.C., shall retain at the source that includes the unit records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the EPA or the Department. The owners and operators bear the burden of proof that the unit is permanently retired.
(6) On the earlier of the following dates, a unit exempt under Rule 62-214.340(2), F.A.C., shall lose its exemption and become an Acid Rain Unit: (i) the date on which the designated representative submits an Acid Rain part application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain part application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under Rule 62-214.340(2), F.A.C., shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

STEP 4
Read the appropriate certification and sign and date.

Certification (for designated representatives only)

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	Date
Gregory M. Nelson	
Signature: Gregory M. Nelson	3/31/04

IN THE CIRCUIT COURT OF THE THIRTEENTH JUDICIAL CIRCUIT
IN AND FOR HILLSBOROUGH COUNTY, FLORIDA

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Plaintiff,

vs. CASE NO.:

TAMPA ELECTRIC COMPANY,

Defendant.
_____/

CONSENT FINAL JUDGMENT

I. INTRODUCTION AND PURPOSE

A. This Consent Final Judgment is entered into between Plaintiff, State of Florida, Department of Environmental Protection (the "DEP"), and Defendant, Tampa Electric Company ("TAMPA ELECTRIC COMPANY"), to reach a settlement of certain matters at issue between them. The Consent Final Judgment provides for the implementation of certain actions, the investigation and implementation of certain pollution prevention technology, and the contribution of funds to assist the DEP in its Bay Regional Air Chemistry Experiment program relating to nitrogen deposition in Tampa Bay.

B. "Consent Final Judgment" means this Consent Final Judgment, including any future modifications, and any reports, plans, specifications and schedules required by the Consent Final Judgment which, upon the approval of each by the DEP, shall be deemed incorporated into and become an enforceable part of this Consent Final Judgment as though each was originally set forth herein.

II. JURISDICTION

A. The DEP is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources, and to administer and enforce the provisions of Chapter 403, Florida Statutes, and the rules promulgated thereunder, Florida Administrative Code ("F.A.C.") Title 62 including the rules which Florida has the responsibility to administer and enforce under the federally approved Florida State Implementation Plan (SIP) and the separate Environmental Protection Agency delegation of PSD authority.

B. This Court has jurisdiction over the subject matter herein and over the Parties hereto pursuant to Chapter 403, Florida Statutes.

C. This Court retains jurisdiction over both the subject matter of this Consent Final Judgment and the Parties during the performance of its terms to enforce compliance therewith, if necessary.

III. PARTIES BOUND

This Consent Final Judgment shall apply to and be binding upon the DEP and TAMPA ELECTRIC COMPANY, (hereinafter individually defined as a "Party" or together defined as "Parties") and their successors and assigns. Each person signing this Consent Final Judgment certifies that he or she is authorized to execute the Consent Final Judgment and to legally bind to it the party on whose behalf he or she signs the Consent Final Judgment.

IV. STATEMENT OF FACTS

A. TAMPA ELECTRIC COMPANY owns and is an operator of the Big Bend coal fired electric generation plant in Hillsborough County. Big Bend generates

electricity from four steam generating boilers which are designated as Big Bend Unit 1, Big Bend Unit 2, Big Bend Unit 3, and Big Bend Unit 4. TAMPA ELECTRIC COMPANY also owns and is an operator of the Gannon coal fired electric generation plant in Hillsborough County. Gannon generates electricity from six steam generating boilers which are designated as Gannon Unit 1, Gannon Unit 2, Gannon Unit 3, Gannon Unit 4, Gannon Unit 5, and Gannon Unit 6.

B. The DEP has alleged that Tampa Electric Company undertook a number of activities at the Gannon and Big Bend Generating Stations without appropriate regulatory review and permits, in violation of Chapter 403, Florida Statutes, and applicable provisions of the federally approved SIP. These activities include, but are not limited to, the following:

1 TAMPA ELECTRIC COMPANY modified, and thereafter operated, its electric generating units at Big Bend and Gannon, which are coal fired electricity generating power plants in Hillsborough County, Florida, without first obtaining appropriate permits authorizing this construction and without installing the best control technology (BACT) to control emissions of nitrogen oxides, sulfur dioxide, and particulate matter, as required by Florida law.

2. As a result of TAMPA ELECTRIC COMPANY's operation of the power plants, these unlawful modifications and the absence of appropriate controls, sulfur dioxide, nitrogen oxides, and particulate matter have been, and still are being, released into the atmosphere aggravating air pollution locally and downwind from these plants.

3. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications at Big Bend. These modifications included, but are not

limited to: (1) replacement of steam drum internals in Big Bend Units 1 and 2 in 1994 and 1991, respectively; (2) replacement of the waterwall in Big Bend Unit 2 in 1994, and (3) replacement of the high temperature reheater in Big Bend Unit 2 in 1994.

4. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

5. At various times, TAMPA ELECTRIC COMPANY commenced construction of modifications to Gannon. These modifications included, but were not limited to: (1) replacement of the furnace floor in Gannon Unit 3 with a new design in 1996; and, (2) replacement of the cyclone in Gannon Unit 4 in 1994.

6. Such modifications by TAMPA ELECTRIC COMPANY were done without obtaining a permit from the DEP and without applying BACT for nitrogen oxide, sulfur dioxide and particulate matter as required by Chapter 403, Florida Statutes.

C. Tampa Electric Company has agreed to the entry of the Consent Final Judgment and has agreed to implement the requirements of the Consent Final Judgment without an admission of liability and in recognition of the benefits of resolving litigation and elimination of such related expenses as settlement of the claims set forth in the Complaint, which Tampa Electric Company believes to be disputed claims. Tampa Electric Company neither admits nor denies the facts set forth in the Complaint and in Section IV.B. of this Consent Final Judgment.

V. REQUIREMENTS OF THE CONSENT FINAL JUDGMENT

A. TAMPA ELECTRIC COMPANY shall shut down coal-fired Units 1, 2, and 6 at Gannon Station and repower Units 3, 4, & 5 for gas to be phased-in between

January 1, 2003 and December 31, 2004. The repowered Units shall meet BACT for nitrogen oxide applicable to combined cycle gas turbines with an emission rate of 3.5 ppm. This requirement shall be included as a permit condition issued through the normal process.

B. TAMPA ELECTRIC COMPANY shall evaluate using "zero-ammonia" nitrogen oxide control technology at its Gannon facility. If, by May, 2000, such technology is found by the DEP to be commercially viable, TAMPA ELECTRIC COMPANY shall install such technology on one of the units it intends to repower so long as the incremental capital cost differential above the cost of Selective Catalytic Reduction (SCR) does not exceed $8 million and TAMPA ELECTRIC COMPANY obtains acceptable performance guarantees and remedies from the manufacturer of the technology. The installation shall be performed as part of the repowering process and shall be completed no later than December 31, 2004. In the event that the DEP does not find that the technology is commercially viable, then by December 31, 2004, TAMPA ELECTRIC COMPANY shall spend up to $8 million to demonstrate alternative commercially viable nitrogen oxide reduction technologies for natural gas-fired or coal-fired generating facilities as determined by the DEP and TAMPA ELECTRIC COMPANY.

C. At Big Bend Station, the new scrubber serving Units 1&2 is currently going through performance testing and is scheduled for commercial operation on or about January 1, 2000. It has a guaranteed removal efficiency of 93% but is the first Unit with a large, high velocity tower serving approximately 800 mega watts TAMPA ELECTRIC COMPANY shall use reasonable commercial efforts to optimize the removal efficiency

to achieve a 95% removal efficiency by May 1, 2002 if such rate is not achieved by commercial operation.

D. TAMPA ELECTRIC COMPANY shall maximize scrubber utilization on all four boilers at Big Bend. The DEP recognizes the need for shut down for operational reasons.

E. TAMPA ELECTRIC COMPANY shall add nitrogen oxide controls, repower or shut down Units 1 through 3 at Big Bend Station by May 2010 and at Unit 4 at Big Bend Station by May 2007. If SCRs or similar nitrogen oxide controls are installed, BACT for nitrogen oxide will be .10 lbs./mmBTU on Unit 4 and .15 lbs./mmBTU on Units 1, 2, and 3.

F TAMPA ELECTRIC COMPANY shall undertake a performance optimization study and a BACT analysis of its electrostatic precipitators and make reasonable upgrades to the electrostatic precipitators at Big Bend Station by May 1, 2003, if the study indicates that reasonable upgrades are necessary to obtain performance optimization.

G. TAMPA ELECTRIC COMPANY shall report to DEP on the technical feasibility of installing a particulate matter continuous emissions monitor on one stack at Big Bend March 1, 2002. If the DEP determines by May 31, 2002 that installation to be technically feasible, TAMPA ELECTRIC COMPANY shall install a particulate matter continuous emissions monitor on one stack at Big Bend station no later than May 1, 2003. Such monitor shall be installed solely for demonstration and informational purposes.

H. TAMPA ELECTRIC COMPANY shall be entitled to retain all sulfur dioxide reduction credits as currently authorized by law and freely trade them as allowed by the acid rain program. These credits were an integral part of the economics of the repowering project. If a credit trading program is developed by state or federal law for nitrogen oxide, TAMPA ELECTRIC COMPANY shall bank such credits obtained from the reductions achieved through the implementation of this Consent Final Judgment, but such credits shall not be eligible for sale to third parties but shall be held for TAMPA ELECTRIC COMPANY's (or any affiliate's) own account.

I. TAMPA ELECTRIC COMPANY shall agree to cooperate with the DEP on its Bay Regional Air Chemistry Experiment BRACE program relating to nitrogen deposition in Tampa Bay, including allowing necessary stack testing access to the DEP, and contributing $2 million dollars to the Hillsborough Environmental Protection Commission (EPC) for use in the BRACE program, in lieu of civil penalties. The DEP will enter into an agreement with EPC to ensure that the funds are spent on the BRACE program. TAMPA ELECTRIC COMPANY shall make the first payment to EPC in the amount of $500,000 by July 1, 2000, and shall pay $500,000 each six months thereafter until the full $2 million dollars has been paid.

J. TAMPA ELECTRIC COMPANY shall collaborate with the DEP to develop and implement State tax policy aimed at emissions reductions and such other supplemental environmental programs which are agreed to by TAMPA ELECTRIC COMPANY and the DEP.

K. TAMPA ELECTRIC COMPANY shall be entitled to relief from the time requirements of this Consent Final Judgment in the event of a force majeure that

includes, among other things, delays in regulatory approvals, construction, labor, material or equipment delays, natural gas and gas transportation availability delays, acts of God or other similar events that are beyond the control of the company and not resulting from its owns actions, for the length of time necessarily imposed by the delay.

L. TAMPA ELECTRIC COMPANY shall be released from civil liability for all past New Source Review (NSR) related acts and State Implementation Plan (SIP) violations associated with the Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS) and NSR related matters set forth herein and in the Complaint.

M. TAMPA ELECTRIC COMPANY shall also be protected from triggering NSR requirements with respect to repairs, maintenance and physical or operation changes during the term of the Consent Final Judgment which term shall remain effective until the actions required hereunder have been implemented.

N. The DEP shall cooperate with TAMPA ELECTRIC COMPANY and the United States Environmental Protection Agency in an effort to clarify the NSR regulations for repairs, maintenance, physical and operation changes in the future.

O. TAMPA ELECTRIC COMPANY's obligation to implement the emissions reductions and other requirements set forth herein will be conditioned on the receipt of necessary federal, state and local environmental permits, and acceptable regulatory treatment, including cost recovery by the Florida Public Service Commission.

P. DEP will defend the terms of this Consent Final Judgment in any action to which it is a party.

VI. MISCELLANEOUS

A. This Consent Final Judgment embodies the entire agreement and understanding of the Parties and supersedes any and all prior agreements, drafts, arrangements, conversations, negotiations or understandings relating to matters provided for in the Consent Final Judgment.

B. This Consent Final Judgment may be executed in one or more counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

C. Each provision of the Consent Final Judgment shall be interpreted in such a manner as to be effective and valid under applicable law, but if any provision of the Consent Final Judgment shall be prohibited or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of the Consent Final Judgment.

D. This Consent Final Judgment is not, and shall not be construed to be, a permit issued pursuant to any federal, State or local law, rule or regulation.

E. If, for any reason, the Court should decline to enter this Consent Final Judgment in the form in which it is lodged, the Consent Final Judgment as lodged is voidable, at the sole discretion of either Party. The Parties agree that because the claims of the DEP contained herein were disputed as to validity and amount, none of the terms of the lodged but voided Consent Final Judgment may be used as evidence in any litigation for any purpose, except with the written consent of TAMPA ELECTRIC COMPANY.

F. Except as provided for herein, there shall be no modifications or amendments of this Consent Final Judgment without written agreement of the Parties to this Consent Final Judgment and approval by the Court.

VII. FINAL JUDGMENT/RETENTION OF JURISDICTION

This Consent Final Judgment constitutes a final judgment in this action. This Court will retain jurisdiction for the purpose of enabling the Parties to apply to the Court at any time for such further order, direction or relief as may be necessary or appropriate for the construction or modification of this Consent Final Judgment, or to effectuate or enforce compliance with its terms, or to resolve disputes.

DONE AND ORDERED IN CHAMBERS this day of _____, 1999.

_____
Circuit Judge

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

By:_____
Secretary of the Florida Department of Environmental Protection

Date: _____

TAMPA ELECTRIC COMPANY

By:_____
John B. Ramil
President

Date: _____

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NOTICE OF FINAL TITLE V AIR OPERATION PERMIT REVISION

In the Matter of an
Application for Permit Revision/Renewal by:

Ms. Karen A. Sheffield
General Manager
Tampa Electric Company
6944 US HWY 41
Apollo Beach, FL 33572-9200

FINAL Permit Project No.: 0570039-017-AV
Big Bend Station
Hillsborough County

Enclosed is the FINAL Permit, No. 0570039-017-AV, for the Title V Air Operation Revision/Renewal for the Big Bend Station located at Big Bend Road, North Ruskin, Hillsborough County. The purpose of this permit is to incorporate the changes approved in air construction permit 0570039-016-AC, which is simultaneously processed with this revision; to make some administrative corrections; and to revise and renew the existing Title V permit.

This permit revision is issued pursuant to Chapter 403, Florida Statutes (F.S.). There were no comments received from Region 4, U.S. EPA, regarding the PROPOSED Permit.

Any party to this order (permit revision) has the right to seek judicial review of the permit revision 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 of Environmental Protection.

Executed in Tallahassee, Florida.

Trina L. Vielhauer, Chief
Bureau of Air Regulation

TLV/clp

FINAL Permit Project No.: 0570039-017-AV
Big Bend Station
Hillsborough County

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL TITLE V AIR OPERATION PERMIT REVISION (including the FINAL Determination and the FINAL Permit) was sent by certified mail before the close of business on _____ to the person listed or as otherwise noted:

Ms. Karen A. Sheffield, R.O.

The undersigned duly designated deputy agency clerk hereby certifies that a copy of this NOTICE OF FINAL TITLE V AIR OPERATION PERMIT REVISION was sent by U.S. Mail before the close of business on _____ to the persons listed or as otherwise noted:

Mr. Gregory M. Nelson, D.R. (Tampa Electric Company)
Mr. Thomas W. Davis, P.E. (E-mail) (ECT)
Ms. Laura Crouch, TEC (E-mail)
Mr. Jerry Campbell, EPCHC (E-mail)
Mr. Jerry Kissel, FDEP-SWD (E-mail)
USEPA, Region 4 (INTERNET E-mail Memorandum)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

_____ _____
(Clerk) (Date)

FINAL Determination

Title V Air Operation Permit Revision/Renewal
FINAL Permit Project No.: 0570039-017-AV
Tampa Electric Company
Big Bend Station

I. Comments.

No comments were received from the USEPA during their 45 day review period of the PROPOSED Permit. Day 45 is December 30, 2004.

II. Conclusion.

In conclusion, the permitting authority hereby issues the FINAL Permit.

UNITED STATES DISTRICT COURT
MIDDLE DISTRICT OF FLORIDA

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	CIVIL ACTION NO. 99-2524
v.	)	CIV-T-23F
	)	
	)	
TAMPA ELECTRIC COMPANY,	)	
	)	
Defendant.	)	
	)	

CONSENT DECREE

WHEREAS, Plaintiff, the United States of America (Plaintiff or the United States), on behalf of the United States Environmental Protection Agency (EPA) filed a Complaint on November 3, 1999, alleging that Defendant, Tampa Electric Company (Tampa Electric) commenced construction of major modifications of major emitting facilities in violation of the Prevention of Significant Deterioration (PSD) requirements at Part C of the Clean Air Act (Act), 42 U.S.C. §§ 7470-7492;

WHEREAS, EPA issued a Notice of Violation with respect to such allegations to Tampa Electric on November 3, 1999 (the NOV);

WHEREAS, the parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm s length; that the parties have voluntarily agreed to this Consent Decree; that implementation of this Consent Decree will

avoid prolonged and complicated litigation between the parties; and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, the United States alleges that the Complaint states a claim upon which relief can be granted against Tampa Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Tampa Electric has not answered or otherwise responded to the Complaint in light of the settlement memorialized in this Consent Decree;

WHEREAS, Tampa Electric has denied and continues to deny the violations alleged in the NOV and the Complaint; maintains that it has been and remains in compliance with the Clean Air Act and is not liable for civil penalties or injunctive relief; and states that it is agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment in and around the Tampa Bay area of Florida;

WHEREAS, Tampa Electric is the first electric utility of those against which the United States brought enforcement actions in November, 1999, to come forward and invest time and effort sufficient to develop a settlement with the United States;

WHEREAS, Tampa Electric s decision to Re-Power some of its coal-fired electric generating Units with natural gas will significantly reduce emissions of both regulated and unregulated pollutants below levels that would have been achieved merely by installing appropriate pollution control technologies on Tampa Electric s existing coal-fired electric generating Units;

WHEREAS, prior to the filing of the Complaint or issuance of the Notice of Violation in this matter, Tampa Electric already had placed in service or installed both scrubbers and

electrostatic precipitators that serve all existing coal-fired electric generating Units at the company s Big Bend electric generating plant;

WHEREAS, the United States recognizes that a BACT Analysis conducted under existing procedures most likely would not find it cost effective to replace Tampa Electric s existing control equipment at Big Bend for particulate matter, in light of the design and performance of that equipment;

WHEREAS, Tampa Electric and the United States have crafted this Consent Decree to take into account physical and operational constraints resulting from the unique, Riley Stoker wet bottom, turbo-fired boiler technology now in operation at Big Bend, which could limit the efficiency of nitrogen oxides emissions controls installed for those boilers;

WHEREAS, Tampa Electric regularly combusts coal with a sulphur content of five or six pounds per mmBTU heat input;

WHEREAS, Tampa Electric is a mid-sized electric utility and is smaller on a financial basis than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, Tampa Electric owns and operates fewer coal-fired electric generating plants than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, the two Tampa Electric plants addressed by this enforcement action constitute over ninety percent of the entire base load generating capacity of Tampa Electric;

WHEREAS, the United States and Tampa Electric have agreed that settlement of this action is in the best interest of the parties and in the public interest, and that entry of this Consent

Decree without further litigation is the most appropriate means of resolving this matter; and

WHEREAS, the United States and Tampa Electric have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint or NOV, it is hereby ORDERED AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter herein and over the parties consenting hereto pursuant to 28 U.S.C. § 1345 and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying Complaint, Tampa Electric waives all objections and defenses that it may have to the claims set forth in the Complaint, the jurisdiction of the Court or to venue in this District. Tampa Electric shall not challenge the terms of this Consent Decree or this Court s jurisdiction to enter and enforce this Consent Decree. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and Tampa Electric. Tampa Electric consents to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. The provisions of this Consent Decree shall apply to and be binding upon the United

States and upon Tampa Electric, its successors and assigns, and Tampa Electric s officers, employees and agents solely in their capacities as such. If Tampa Electric proposes to sell or transfer any of its real property or operations subject to this Consent Decree, it shall advise the purchaser or transferee in writing of the existence of this Consent Decree, and shall send a copy of such written notification by certified mail, return receipt requested, to EPA sixty (60) days before such sale or transfer. Tampa Electric shall not be relieved of its responsibility to comply with all requirements of this Consent Decree unless the purchaser or transferee assumes responsibility for full performance of Tampa Electric s responsibilities under this Consent Decree, including liabilities for nonperformance. Tampa Electric shall not purchase or otherwise acquire capacity and/or energy from a third party in lieu of obtaining it from Gannon or Big Bend unless the seller or provider agrees that the facilities providing such capacity and/or energy will meet the emission control requirements set forth in this Consent Decree or equivalent requirements approved in advance by the United States.

3. Tampa Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization performing any of the work described in Sections IV or VII of this Consent Decree. Notwithstanding any retention of contractors, subcontractors or agents to perform any work required under this Consent Decree, Tampa Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Tampa Electric shall not assert as a defense the failure of its employees, servants, agents, or contractors to take actions

necessary to comply with this Consent Decree, unless Tampa Electric establishes that such failure resulted from a Force Majeure event as defined in this Consent Decree.

III. DEFINITIONS

4. Alternative Coal shall mean coal with a sulphur content of no more than 2.2 lb/mmBTU, on an as determined basis.

5. BACT Analysis shall mean the technical study, analysis, review, and selection of recommendations typically performed in connection with an application for a PSD permit. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in conformance with applicable federal and state regulations and guidance describing the process and analysis for determining Best Available Control Technology (BACT).

6. Big Bend shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric and located in Hillsborough County, Florida, which presently includes four steam generating boilers and associated and ancillary systems and equipment, known as Big Bend Units 1, 2, 3, and 4.

7. Consent Decree shall mean this Consent Decree and the Appendix thereto.

8. Emission Rate shall mean the average number of pounds of pollutant emitted per million BTU of heat input (lb/mmBTU) or the average concentration of a pollutant in parts per million by volume (ppm), as dictated by the unit of measure specified for the rate in question, where:

A. in the case of a coal-fired, steam electric generating unit, such rates shall be

calculated as a 30 day rolling average. A 30 day rolling average for an Emission Rate expressed as lb/mmBTU shall be determined by calculating the emission rate for a given operating day, and then arithmetically averaging the emission rates for the previous 29 operating days with that date. A new 30 day rolling average shall be calculated for each new operating day;

B. in the case of a gas-fired, electric generating unit, such rates shall be calculated as a 24-hour rolling average, excluding periods of start up, shutdown, and malfunction as provided by applicable Florida regulations at the time the Emission Rate is calculated. A rolling average for Emission Rates expressed as ppm shall be determined on a given day by summing hourly emission rates for the immediately preceding 24-hour period and dividing by 24;

C. the reference methods for determining Emission Rates for SO_2 and NO_x shall be those specified in 40 C.F.R. Part 75, Appendix F. The reference methods for determining Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, Method 5B, or Method 17; and

D. nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by methods other than the reference methods specified herein.

9. EPA shall mean the United States Environmental Protection Agency.

10. Gannon shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric, located in Hillsborough County, Florida, which presently includes six steam generating boilers and associated and ancillary systems and

equipment, known as Gannon Units 1, 2, 3, 4, 5, and 6. Tampa Electric intends to rename Gannon Bayside Power Station upon completion of the Re-Powering required under this Consent Decree.

11. lb/mmBTU shall mean pounds per million British Thermal Units of heat input.

12. NOx shall mean oxides of nitrogen.

13. NOV shall mean the Notice of Violation issued by EPA to Tampa Electric dated November 3, 1999.

14. PM shall mean total particulate matter, and the reference method for measuring PM shall be that specified in the definition of Emission Rate in this Consent Decree.

15. ppm shall mean parts per million by dry volume, corrected to 15% O_2.

16. Project Dollars shall mean Tampa Electric s expenditures and payments incurred or made in carrying out the dollar-limited projects identified in Paragraph 35 of Section IV of this Consent Decree (Early Reductions of NO_x from Big Bend Units 1 through 3) and in Section VII of this Consent Decree (NO_x Reduction Projects and Mitigation Projects), to the extent that such expenditures or payments both: (A) comply with the Project Dollar and other requirements set by this Consent Decree for such expenditures and payments in Section VII and in Paragraph 35 of Section IV of this Consent Decree, and (B) constitute either Tampa Electric s properly documented external costs for contractors, vendors, as well as equipment, or its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects.

17. PSD shall mean Prevention of Significant Deterioration within the meaning of Part C of the Clean Air Act, 42 U.S.C. §§ 7470, et seq.

18. Re-Power shall mean the removal or permanent disabling of devices, systems, equipment, and ancillary or supporting systems at a Gannon or Big Bend Unit such that the Unit cannot be fired with coal, and the installation of all devices, systems, equipment, and ancillary or supporting systems needed to fire such Unit with natural gas under the limits set in this Consent Decree (or with No. 2 fuel oil, as a back up fuel only, and under the limits specified by this Consent Decree) plus installation of the control technology and compliance with the Emission Rates called for under this Consent Decree.

19. Reserve / Standby shall mean those devices, systems, equipment, and ancillary or supporting systems that: (1) are not used as part of the Units that must be Re-Powered under Paragraph 26, (2) are not in operation subsequent to the Re-Powering required under Paragraph 26, (3) are maintained and held by Tampa Electric for system reliability purposes, and (4) may be restarted only by Re-Powering.

20. SCR shall mean Selective Catalytic Reduction.

21. Shutdown shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel nor produce any steam for electricity production, other than through Re-Powering.

22. S O_2" shall mean sulphur dioxide.

23. Title V Permit shall mean the permit required under Subchapter V of the Clean Air Act, 42 U.S.C. § 7661, et seq.

24. Total Baseline Emissions shall mean calendar year 1998 emissions of NO_x, SO_2, and PM comprised of the following amounts for each pollutant:

A. for Gannon: 30,763 tons of NO_x, 64,620 tons of SO_2, and 1,914 tons of PM; and

B. for Big Bend: 36,077 tons of NO_x , 107,334 tons of SO_2, and 3,002 tons of PM.

25. Unit shall mean for the purpose of this Consent Decree a generator, the steam turbine that drives the generator, the boiler that produces the steam for the steam turbine, the equipment necessary to operate the generator, turbine and boiler, and all ancillary equipment, including pollution control equipment or systems necessary for the production of electricity. An electric generating plant may be comprised of one or more Units.

IV. EMISSIONS REDUCTIONS AND CONTROLS GANNON AND BIG BEND

A. GANNON

26. Consent Decree-Required Re-Powering of Gannon. Tampa Electric shall Re-Power Units at Gannon with a coal-fired generating capacity of no less than 550 MW (Megawatt), as follows.

A. On or before May 1, 2003, Tampa Electric shall Re-Power Units with a coal-fired generating capacity of no less than 200 MW. On or before December 31, 2004, Tampa Electric shall Re-Power additional Units with a coal-fired generating capacity equal to or greater than the difference between 550 MW of coal-fired generating capacity and the MW value of coal-fired generating capacity that Tampa Electric Re-Powered in complying with the first sentence of this

Subparagraph A.

B. All Re-Powering required by this Paragraph shall include installation and operation of SCR, other pollution control technology approved in advance and in writing by EPA, or any innovative technology demonstration project approved pursuant to Paragraph, 52.C to control Unit emissions. Each Re-Powered Unit shall, in conformance with the definition of Re-Power, use natural gas as its primary fuel and shall meet an Emission Rate for NO_x of no greater than 3.5 ppm.

C. A Unit Re-Powered under this or any other provision of this Consent Decree may be fired with No. 2 fuel oil if and only if: (1) the Unit cannot be fired with natural gas; (2) the Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil; (3) the oil to be used in firing the Unit has a sulphur content of less than 0.05 percent (by weight); (4) Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and (5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

D. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing such Re-Powering. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA-approved control technology and a NO_x Emission Rate no greater than 3.5 ppm.

27. Schedule for Shutdown of Units. Tampa Electric shall Shutdown and cease any and all operation of all six (6) Gannon coal-fired boilers with a combined coal-fired capacity of not less than 1194 MW on or before December 31, 2004. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby, unless such Unit is to be, or has been, Re-Powered under Paragraph 26, above. If Tampa Electric later decides to restart any Shutdown Unit retained on Reserve / Standby, then prior to such re-start, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit to meet the NO_x Emission Rate established in the PSD Permit or an Emission Rate for NO_x of 3.5 ppm, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). For any Unit Shutdown and placed on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any such Unit, complies with all requirements issued in such a permit, and complies with all other requirements of this Consent Decree applicable to Re-Powering.

28. Permanent Bar on Combustion of Coal. Commencing on January 1, 2005, Tampa

Electric shall not combust coal in the operation of any Unit at Gannon.

B. BIG BEND

29. Initial Reduction and Control of SO_2 Emissions from Big Bend Units 1 and 2 . Commencing upon the later of the date of entry of this Consent Decree or September 1, 2000, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 1 and 2 at all times that either Unit 1 or 2 is in operation. Tampa Electric shall operate the scrubber so that at least 95% of all the SO_2 contained in the flue gas entering the scrubber is removed. Notwithstanding the requirement to operate the scrubber at all times Unit 1 or 2 is operating, the following operating conditions shall apply:

A. Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric:

(1) in calendar year 2000, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than sixty (60) calendar days, or any part thereof (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the sixty (60) day limit), and in calendar years 2001 - 2009, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than forty-five (45) calendar days, or any part thereof, in any calendar year (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the forty-five (45) day limit) ; or

(2) must operate Unit 1 and/or 2 in any calendar year from 2000 through 2009 either to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 1 and/or 2 to meet such emergency.

B. Whenever Tampa Electric operates Units 1 and/or 2 without all emissions from such Unit(s) being treated by the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at the Unit(s) operating during the outage (except for coal already bunkered in the hopper(s) for Units 1 or 2 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Units1 and/or 2; and (3) continue to control SO_2 emissions from Big Bend Units 1 and/or 2 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3).

C. In calendar years 2010 through 2012, Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric complies with the requirements of Subparagraphs A and B, above, and uses only coal with a sulphur content of 1.2 lb/mmBTU, or less, in place of

Alternative Coal.

D. If Tampa Electric Re-Powers Big Bend Unit 1 or 2, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon such compliance the provisions of Subparagraphs 29.A, 29.B, and 29.C shall not apply to the affected Unit.

30. Initial Reduction and Control of SO_2 Emissions from Big Bend Unit 3. Commencing upon entry of the Consent Decree, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 3 and 4 at all times that Unit 3 is in operation. When Big Bend Units 3 and 4 are both operating, Tampa Electric shall operate the scrubber so that at least 93% of all the SO_2 contained in the flue gas entering the scrubber is removed. When Big Bend Unit 3 alone is operating, until May 1, 2002, Tampa Electric shall operate the scrubber so that at least 93% of all SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 for Unit 3 does not exceed 0.35 lb/mmBTU. When Unit 3 alone is operating, from May 1, 2002 until January 1, 2010, Tampa Electric shall operate the scrubber so that at least 95% of the SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 does not exceed 0.30 lb/mmBTU. Notwithstanding the requirement to operate the scrubber at all times Unit 3 is operating, and providing Tampa Electric is otherwise in compliance with this Consent Decree, the following operating conditions shall apply:

A. In any calendar year from 2000 through 2009, Tampa Electric may operate Unit 3 in the case of outages of the scrubber serving Unit 3, but only so long as Tampa

Electric:

(1) does not operate Unit 3 during outages on more than thirty (30) calendar days, or any part thereof, in any calendar year; or

(2) must operate Unit 3 either: to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 3 to meet such emergency.

B. Whenever Tampa Electric operates Unit 3 without treating all emissions from that Unit with the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at Unit 3 during the outage (except for coal already bunkered in the hopper(s) for Unit 3 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Unit 3; and (3) continue to control SO_2 emissions from Big Bend Unit 3 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units, 1, 2, and 3).

C. If Tampa Electric Re-Powers Big Bend Unit 3, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon compliance with Paragraph 40 the provisions of Subparagraphs 30.A and 30.B

shall not apply to Unit 3.

D. Nothing in this Consent Decree shall alter requirements of the New Source Performance Standards (NSPS), 40 C.F.R. Part 60 Subpart Da, that apply to operation of the scrubber serving Unit 4.

31. Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3. Tampa Electric shall maximize the availability of the scrubbers to treat the emissions of Big Bend Units 1, 2, and 3, as follows:

A. As soon as possible after entry of this Consent Decree, Tampa Electric shall submit to EPA for review and approval a plan addressing all operation and maintenance changes to be made that would maximize the availability of the existing scrubbers treating emissions of SO_2 from Big Bend Units 1 and 2, and from Unit 3. In order to improve operations and maintenance practices as soon as possible, Tampa Electric may submit the plan in two phases.

(1) Each phase of the plan proposed by Tampa Electric shall include a schedule pursuant to which Tampa Electric will implement measures relating to operation and maintenance of the scrubbers called for by that phase of the plan, within sixty days of its approval by EPA. Tampa Electric shall implement each phase of the plan as approved by EPA. Such plan may be modified from time to time with prior written approval of EPA.

(2) The proposed plan shall include operation and maintenance activities that will minimize instances during which SO_2 emissions are not scrubbed, including but not limited to improvements in the flexibility of scheduling maintenance on the

scrubbers, increases in the stock of spare parts kept on hand to repair the scrubbers, a commitment to use of overtime labor to perform work necessary to minimize periods when the scrubbers are not functioning, and use of all existing capacity at Big Bend and Gannon Units that are served by available, operational pollution control equipment to minimize pollutant emissions while meeting power needs.

(3) If Tampa Electric elects to submit the plan to EPA in two phases, the first phase to be submitted shall address, at a minimum, use of overtime hours to accomplish repairs and maintenance of the scrubber and increasing the stock of scrubber spare parts that Tampa Electric shall keep at Big Bend to speed future maintenance and repairs. If Tampa Electric elects to submit the plan in two phases, EPA shall complete review of the first phase within fifteen business days of receipt. For the second phase of the plan or submission of the plan in its entirety, EPA shall complete review of such plan or phase thereof within 60 days of receipt. Within sixty days after EPA s approval of the plan or any phase of the plan, Tampa Electric shall complete implementation of that plan or phase and continue operation under it subject only to the terms of this Consent Decree.

32. PM Emission Minimization and Monitoring at Big Bend.

A. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete an optimization study which shall recommend the best operational practices to minimize emissions from each Electrostatic Precipitator (ESP) and shall deliver the completed study to EPA for review and approval. Tampa

Electric shall implement these recommendations within sixty days after EPA has approved them and shall operate each ESP in conformance with the study and its recommendations until otherwise specified under this Consent Decree.

B. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete a BACT Analysis for upgrading each existing ESP now located at Big Bend and shall deliver the Analysis to EPA for review and approval. Notwithstanding the definition of BACT Analysis in this Consent Decree, Tampa Electric need not consider in this BACT Analysis the replacement of any existing ESP with a new ESP, scrubber, or baghouse, or the installation of a supplemental pollution control device of similar cost to a replacement ESP, scrubber, or baghouse. Tampa Electric shall simultaneously deliver to EPA all documents that support the BACT Analysis or that were considered in preparing the Analysis. Tampa Electric shall retain a qualified contractor to assist in the performance and completion of the BACT Analysis. On or before May 1, 2004, after EPA approval of the recommendation(s) made by the BACT Analysis, Tampa Electric shall complete installation of all equipment called for in the recommendation(s) of the Analysis and thereafter shall operate each ESP in conformance with the recommendation(s), including compliance with the Emission Rate(s) specified by the recommendation(s).

C. Within six months after Tampa Electric completes installation of the equipment called for by the BACT Analysis, as approved by EPA, Tampa Electric shall revise the previous optimization study and shall recommend the best operational

practices to minimize emissions from each ESP, taking into account the recommendations from the BACT Analysis required by this Paragraph, and shall deliver the completed study to EPA for review and approval. Commencing no later than 180 days after EPA approves the study and its recommendation(s), Tampa Electric shall operate each ESP in conformance with the study s recommendation.

D. Tampa Electric shall include the recommended operational practices for each ESP and the recommendations from the BACT Analysis in Tampa Electric s Title V Permit application and all other relevant applications for operating or construction permits.

E. Installation and Operation of a PM Monitor. On or before March 1, 2002, Defendant shall install, calibrate, and commence continuous operation of a continuous particulate matter emissions monitor (PM CEM) in the duct at Big Bend that services Unit 4. Data from the PM CEM shall be used by Tampa Electric, at a minimum, to monitor progress in reducing PM emissions.

F. Continuous operation of the PM CEM shall mean operation at all times that Unit 4 operates, except for periods of malfunction of the PM CEM or routine maintenance performed on the PM CEM. If after Tampa Electric operates this PM CEM for at least two years, and if the parties then agree that it is infeasible to sustain continuous operation of the PM CEM, Tampa Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEM and a

proposal for an alternative monitoring protocol. Until EPA approves such plan, Tampa Electric shall continue to operate the PM CEM.

G. Installation and Operation of Second PM Monitor. If Tampa Electric advises EPA, pursuant to Paragraph 36, that it has elected to continue to combust coal at Big Bend Units 1, 2, or 3, and Tampa Electric has not ceased operating the first PM CEM as described in Subparagraph F, above, then Tampa Electric shall install, calibrate, and commence continuous operation of a PM CEM on a second duct at Big Bend on or before May 1, 2007. The requirement to operate a PM CEM under any provision of this Paragraph shall terminate if and when the Unit monitored by the PM CEM is Re-Powered.

H. Testing and Reporting Requirement. Prior to installation of the PM CEM on each duct, Tampa Electric shall conduct a stack test on each stack at Big Bend on at least an annual basis and report its results to EPA as part of the quarterly report under Section V. The stack test requirement in this Subparagraph may be satisfied by Tampa Electric s annual stack tests conducted as required by its permit from the State of Florida. Following installation of each PM CEM, Defendant shall include in its quarterly reports to EPA pursuant to Section V all data recorded by the PM CEM, in electronic format, if available.

I. Nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by the PM CEMs.

33. Election for Big Bend Unit 4: Shutdown, Re-Power, or Continued Combustion of Coal.

Tampa Electric shall advise EPA in writing, on or before May 1, 2005, whether Big Bend Unit 4 will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

34. Reduction of NO_x at Big Bend Unit 4 after 2005 Election. Based on Tampa Electric s election in Paragraph 33, Tampa Electric shall take one of the following actions:

A. If Tampa Electric elects to continue firing Unit 4 with coal, on or before June 1, 2007, Tampa Electric shall install and commence operation of SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the coal-fired Emission Rate of NO_x from Unit 4 to no more than 0.10 lb/mmBTU. Thereafter, Tampa Electric shall continue operation of SCR or other EPA approved control technology, and Tampa Electric shall continue to meet an Emission Rate for NO_x from Unit 4 no greater than 0.10 lb/mmBTU; or

B. If Tampa Electric elects to Re-Power Unit 4, Tampa Electric shall not combust coal at Unit 4 on or after June 1, 2007. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of the Re-Powering of Unit 4. In applying for such permit, Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent; or

C. If Tampa Electric elects to Shutdown Big Bend Unit 4, Tampa Electric shall complete Shutdown of Big Bend Unit 4 on or before June 1, 2007.

Notwithstanding the requirements of this Subparagraph, Tampa Electric may retain this Unit, after it is Shutdown pursuant to this Subparagraph, on Reserve / Standby. If Tampa Electric later decides to restart Unit 4 then, prior to such restart, Tampa Electric shall timely apply for a PSD permit, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Subparagraph, Tampa Electric may never again use coal to fire that Unit.

D. Notwithstanding the provisions of Subparagraphs B and C above or the definition of Re-Power in this Consent Decree, Tampa Electric may also elect to fuel Big Bend Unit 4 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in this Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

35. Early Reductions of NO_x from Big Bend Units 1 through 3: On or before December 31, 2001, Tampa Electric shall submit to EPA for review and comment a plan to reduce NO_x emissions from Big Bend Units 1, 2 and 3, through the expenditure of up to $3 million

Project Dollars on combustion optimization using commercially available methods, techniques, systems, or equipment, or combinations thereof. Subject only to the financial limit stated in the previous sentence, for Units 1 and 2 the goal of the combustion optimization shall be to reduce the NO_x Emission Rate by at least 30% when compared against the NO_x Emissions Rate for these Units during calendar year 1998, which the United States and Tampa Electric agree was 0.86 lb/mmBTU. For Unit 3 the goal of the combustion optimization shall be to reduce the NO_x Emissions Rate by at least 15% when compared against the NO_x Emission Rate for this Unit during calendar year 1998, which the United States and Tampa Electric agree was 0.57 lb/mmBTU. If the financial limit in this Paragraph precludes designing and installing combustion controls that will meet the percentage reduction goals for the NO_x Emission Rates specified in this Paragraph for all three Units, then Tampa Electric s plan shall first maximize the Emission Rate reductions at Units 1 and 2 and then at Unit 3. Unless the United States has sought dispute resolution on Tampa Electric s plan on or before May 30, 2002, Tampa Electric shall implement all aspects of its plan at Big Bend Units 1, 2, and 3 on or before December 31, 2002. On or before April 1, 2003, Tampa Electric shall submit to EPA a report that documents the date(s) of complete implementation of the plan, the results obtained from implementing the plan, including the emission reductions or benefits achieved, and the Project Dollars expended by Tampa Electric in implementing the plan.

36. Election for Big Bend Units 1 through 3: Shutdown, Re-Power, or Continued Combustion of Coal. Tampa Electric shall advise EPA in writing, on or before May 1,

2007, whether Big Bend Units 1, 2, or 3, or any combination of them, will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

37. Further NO_x Reduction Requirements if Big Bend Units 1, 2, and/or 3 Remain Coal-fired. If Tampa Electric advises EPA in writing, pursuant to Paragraph 36, above, that Tampa Electric will continue to combust coal at Units 1, 2, and/or 3, then:

A. Subject only to Subparagraphs B and D, Tampa Electric shall timely solicit contract proposals to acquire, install, and operate SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the Emission Rate of NO_x to no more than 0.10 lb/mmBTU at each Unit that will combust coal. Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve an Emission Rate of NO_x on each such Unit no less stringent than 0.10 lb/mmBTU.

B. Notwithstanding Subparagraph A, Tampa Electric shall not be required to install SCR to limit the Emission Rate of NO_x at Units 1, 2 and/or 3 to 0.10 lb/mmBTU if the installation cost ceiling contained in this Paragraph will be exceeded by such installation. If Tampa Electric decides to continue burning coal at Units 1, 2 and 3, the installation cost ceiling for SCR at Units 1, 2, and 3 shall be three times the cost of installing SCR at Big Bend Unit 4 plus forty-five (45%) percent of the cost of installing SCR at Big Bend 4. If Tampa Electric decides to continue burning coal at only two Units at Big Bend, the installation cost ceiling for SCR at those two Units shall be two times the cost of installing SCR at Big Bend 4 plus forty-five (45) percent of the cost of installing SCR at Big Bend Unit 4. If

Tampa Electric decides to continue burning coal at only one Unit at Big Bend, the installation cost ceiling for SCR at that Unit shall be the cost of installing SCR at Big Bend 4 plus forty five (45) percent.

C. If, based on the contract proposals obtained under Subparagraph A, Tampa Electric determines that the projected cost of proposed control equipment satisfying a 0.10 lb/mmBTU Emission Rate will not exceed the installation cost ceiling, Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve a NO_x Emission Rate on each Unit no less stringent than 0.10 lb/mmBTU. If, based on the contract proposals, Tampa Electric determines that the projected cost will exceed the installation cost ceiling, Tampa Electric shall so advise EPA and shall provide EPA with the basis for Tampa Electric s determination, including all documentation sufficient to replicate and evaluate Tampa Electric s cost projections.

D. Unless EPA contests Tampa Electric s determination that the installation cost ceiling will be exceeded by installing control equipment to reduce NO_x emissions to 0.10 lb/mmBTU or less, Tampa Electric shall install, at each Unit that will continue to combust coal, the NO_x control technology designed to achieve the lowest Emission Rate that can be attained within the installation cost ceiling. Notwithstanding any provision of this Consent Decree, including the installation cost ceiling, Tampa Electric shall install NO_x control technology that is designed to achieve an Emission Rate no less stringent than 0.15 lb/mmBTU. Each Unit combusting coal and its NO_x controls shall meet the Emission Rate for which they

are designed.

E. Tampa Electric shall acquire, install, commence operating emission control equipment, and meet the applicable Emission Rate for NO_x at each of the Units to remain coal-fired, as follows: (1) for the first of the Units to remain coal-fired, or if only one Unit is to be coal-fired, on or before May 1, 2008; (2) for the second Unit, if there is one, on or before May 1, 2009; (3) for the third Unit, if there is one, on or before May 1, 2010.

38. Tampa Electric s NO_x Reduction Requirements if Tampa Electric Re-Powers Units 1, 2, and/or 3 . If, by May 1, 2007, Tampa Electric advises EPA that Tampa Electric has elected to Re-Power one or more of Units 1, 2, and 3 at Big Bend, then Tampa Electric shall complete all steps necessary to accomplish such Re-Powering in a time frame to commence operation of the Re-Powered Unit(s) no later than May 1, 2010. Any Unit(s) to be replaced by a Re-Powered Unit may continue to operate until the earlier of six months after the date the Re-Powered Unit begins commercial operation or December 31, 2010. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of any Re-Powered Unit at Big Bend. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate any Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent. Notwithstanding the provisions of this Paragraph or the definition of Re-Power in this

Consent Decree, Tampa Electric may also elect to fuel Units 1, 2, or 3 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in any of these Units, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

39. Requirements Applicable to Big Bend Units 1, 2, and/or 3 if Shutdown. If Tampa Electric elects to Shutdown one or more of Units1, 2, and 3, Tampa Electric shall complete Shutdown of the first such Unit on or before May 1, 2008; of the second Unit, if applicable, on or before May 1, 2009, and of the third Unit, if applicable, on or before May 1, 2010. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby. If Tampa Electric later decides to restart such Unit retained on Reserve / Standby by Re-Powering it then, prior to such restart, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as result of that application, including installation of BACT and its corresponding Emission Rate determined at the time of the restart. Tampa Electric shall operate each Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Paragraph, Tampa Electric may never again use coal to fire that Unit.

For any Unit Shutdown and placed on on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any of such Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

40. Further SO_2 Reduction Requirements if Big Bend Units 1, 2, or 3 Remains Coal-fired. If Tampa Electric elects under Paragraph 36 to continue combusting coal at Units 1, 2, and/or 3, Tampa Electric shall meet the following requirements.

A. Removal Efficiency or Emission Rate. Commencing on dates set forth in Subparagraph C and continuing thereafter, Tampa Electric shall operate coal-fired Units and the scrubbers that serve those Units so that emissions from the Units shall meet at least one of the following limits:

(1) the scrubber shall remove at least 95% of the SO_2 in the flue gas that entered the scrubber; or

(2) the Emission Rate for SO_2 from each Unit does not exceed 0.25 lb/mmBTU.

B. Availability Criteria. Commencing on the deadlines set in this Paragraph and continuing thereafter, Tampa Electric shall not allow emissions of SO_2 from Big Bend Units 1, 2, or 3 without scrubbing the flue gas from those Units and using other equipment designed to control SO_2 emissions. Notwithstanding the preceding sentence, to the extent that the Clean Air Act New Source Performance Standards identify circumstances during which Bend Unit 4 may operate without

its scrubber, this Consent Decree shall allow Big Bend Units1, 2, and/or 3 to operate when those same circumstances are present at Big Bend Units 1, 2, and/or 3.

C. Deadlines. Big Bend Unit 3 and the scrubber(s) serving it shall be subject to the requirements of this Paragraph beginning January 1, 2010 and continuing thereafter. Until January 1, 2010, Tampa Electric shall control SO_2 emissions from Unit 3 as required by Paragraphs 30 and 31. Big Bend Units 1 and 2 and the scrubber(s) serving them shall be subject to the requirements of this Paragraph beginning January 1, 2013 and continuing thereafter. Until January 1, 2013, Tampa Electric shall control SO_2 emissions from Units 1 and 2 as required by Paragraphs 29 and 31.

D. Nothing in this Consent Decree shall alter requirements of NSPS, 40 C.F.R. Part 60 Subpart Da, that apply to operation of Unit 4 and the scrubber serving it.

C. BIG BEND AND GANNON -- PERMITS AND RESOLUTION OF CLAIMS

41. Timely Application for Permits. Except as otherwise stated in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Tampa Electric to secure a permit to authorize constructing or operating any device under this Consent Decree, Tampa Electric shall make such application in a timely manner. Such applications shall be completed and submitted to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Failure to comply with this provision shall bar any use by Tampa Electric of the Force

Majeure provisions of this Consent Decree.

42. Title V Permits.

A. On or before January 1, 2004, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Gannon, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

B. On or before January 1, 2009, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Big Bend, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

C. Except as this Consent Decree expressly requires otherwise, this Consent Decree shall not be construed to require Tampa Electric to apply for or obtain a permit pursuant to the Prevention of Significant Deterioration requirements of the Clean Air Act for any work performed by Tampa Electric within the scope of the Resolution of Claims provisions of Paragraphs 43 and 44, below.

43. Resolution of Past Claims - This Consent Decree resolves all of Plaintiff s civil claims

for liability arising from violations of either: (1) the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401, et seq at Units at Big Bend or Gannon, or (2) 40 C.F.R. Section 60.14 at Units at Big Bend or Gannon, that :

A. are alleged in the Complaint filed November 3, 1999, or in the NOV issued on that date;

B. could have been alleged by the United States in the Complaint filed November 3, 1999, or in the NOV issued on that date; or

C. have arisen from Tampa Electric s actions that occurred between November 3, 1999 and the date on which this Consent Decree is entered by the Court.

44. Resolution of Future Claims - Covenant not to Sue . The United States covenants not to sue Tampa Electric for civil claims arising from the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401 et seq., at Big Bend or Gannon Units and that are based on failure to obtain PSD or nonattainment New Source Review (NSR) permits for:

A. work that this Consent Decree expressly directs Tampa Electric to undertake; or

B. physical changes or changes in the method of operation of Big Bend or Gannon Units not required by this Consent Decree, if and only if:

(1) such change is commenced after Tampa Electric is implementing the plan, or the first phase of the plan if applicable, approved by EPA under Paragraph 31 (Optimizing Availability of Scrubbers),

(2) such change is commenced, within the meaning of 40 C.F.R. Section

52.21(b)(9), during the time this Consent Decree applies to the Unit at which this change has been made ;

(3) Tampa Electric is otherwise in compliance with this Consent Decree;

(4) hourly Emission Rates of NO_x, SO_2, or PM at the changed Unit(s) do not exceed their respective hourly Emission Rates prior to the change, as measured by 40 C.F.R. § 60.14(h); and

(5) in any calendar year following the change, emissions of no pollutant within the scope of Total Baseline Emissions exceed the emissions of that pollutant in the Total Baseline Emissions.

45. Separate Limitation on Resolution of Claims. Notwithstanding the provisions of Section XIII (Termination), the provisions of Paragraph 44 (Resolution of Future Claims - Covenant Not to Sue) shall terminate at Gannon and Big Bend, as follows. On December 31, 2006, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Gannon. On December 31, 2012, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Big Bend. If Tampa Electric Re-Powers any Unit at Big Bend under the terms provided by this Consent Decree, then for each such Unit the provisions of Paragraph 44 shall terminate two years after each such Unit is Re-Powered or on December 31, 2012, whichever is earlier.

46. Exclusion of Certain Emission Allowances. For any and all actions taken by Tampa Electric pursuant to the terms of this Consent Decree, including but not limited to

upgrading of ESPs and scrubbers, installation of NO_x controls, Re-Powering, and Shutdown, Tampa Electric shall not use or sell any resulting NO_x or SO_2 emission allowances or credits in any emission trading or marketing program of any kind; provided, however, that:

A. SO_2 credits allocated to Tampa Electric by the Administrator of EPA under the Act, due to the Re-Powering or Shutdown of Gannon, may be retained by Tampa Electric during the year in which they are allocated, but only for Tampa Electric s own use in meeting any acid rain requirement imposed under the Act. For any such allowances not used by Tampa Electric for this purpose by June 30 of the following calendar year, Tampa Electric shall not use, sell, trade, or otherwise transfer these allowances for its benefit or the benefit of a third party unless such a transfer would result in the retiring of such allowances without their ever being used.

B. If Tampa Electric decides to Re-Power any Unit at Big Bend, then Tampa Electric shall be entitled to retain for any purpose under law the difference between the emission allowances that would have resulted from installing BACT-level NO_x and SO_2 controls at the existing coal-fired Unit and the emission allowances that result from Re-Powering that Unit. Before Tampa Electric uses any allowances within the scope of this Subparagraph, Tampa Electric shall submit the calculation of the net emission allowances for approval by the United States.

C. Nothing in this Consent Decree shall preclude Tampa Electric from using or

selling emission allowances arising from Tampa Electric s activities occurring prior to December 31, 1999, or Tampa Electric s activities after that date that are not related to actions required of Tampa Electric under this Consent Decree. The United States and Tampa Electric agree that the operation of the SO_2 scrubber serving Big Bend Units 1 and 2 meets the requirements of this Subparagraph, and that emission allowances resulting from the operation of this scrubber shall not be treated as an activity related to or required under this Consent Decree.

V. REPORTING AND RECORD KEEPING

47. Beginning at the end of the first calendar quarter after entry of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Tampa Electric shall submit to EPA a quarterly report, consistent with the form attached to this Consent Decree as the Appendix, within thirty (30) days after the end of each calendar quarter until this Consent Decree is terminated.

48. Tampa Electric s report shall be signed by Tampa Electric s Vice President, Environmental and Fuels, or, in his or her absence, Vice President, Energy Supply, or higher ranking official, and shall contain the following certification:

> I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I understand that there are significant penalties for making misrepresentations to or misleading the United States.

VI. CIVIL PENALTY

49. Within thirty (30) calendar days of entry of this Consent Decree, Tampa Electric shall pay to the United States a civil penalty in the amount of $3.5 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing the USAO File Number and DOJ Case Number 90-5-2-1-06932 and the civil action case name and case number of this action. The costs of such EFT shall be Tampa Electric s responsibility. Payment shall be made in accordance with instructions provided by the Financial Litigation Unit of the U.S. Attorney's Office for the Middle District of Florida. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. Tampa Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1- 06932, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 82 (Notice). Failure to timely pay the civil penalty shall subject Tampa Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Tampa Electric liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

VII. NO_x REDUCTION PROJECTS AND MITIGATION PROJECTS

50. Tampa Electric shall submit plans for and shall implement the NO_x Reduction and Other Mitigation Projects (referred to together as Projects) described in this Section, and in Paragraph 35 of this Consent Decree, in compliance with the schedules and terms of this

Consent Decree. In performing these Projects, Tampa Electric shall spend no less than $10 million in Project Dollars, in total, unless the Additional NO_x Reduction Project(s) selected under Paragraph 52.C is estimated to cost more than $5 million, in which case Tampa Electric shall spend no less than $10 million but no more than $11 million in Project Dollars, in total. Tampa Electric shall expend the full amount of the Project Dollars required by this Paragraph on or before May 1, 2010. Tampa Electric shall maintain for review by EPA, upon its request, all documents identifying Project Dollars spent by Tampa Electric.

51. All plans and reports prepared by Tampa Electric pursuant to the requirements of Paragraph 35 and this Section of the Consent Decree shall be publicly available without charge.

52. Tampa Electric shall submit the required plans for and complete the following Projects:

A. Early NO_x reductions through combustion optimization as described in Paragraph 35 of this Consent Decree.

B. Performance of Air Chemistry Work in Tampa Bay Estuary. Tampa Electric shall expend no more than $2 million Project Dollars in conducting or financing stack tests, emissions estimation, ambient air monitoring, data acquisition and analysis, and any combination thereof that: (1) is not otherwise required by law, (2) will provide data or analysis that is not already available, (3) will complement work carried out by other persons examining the air chemistry of Tampa Bay Estuary, and (4) will help close gaps in current understanding of air chemistry in the Tampa Bay Estuary. Tampa Electric shall either conduct this

work itself, fund other persons already conducting such work on a non-profit basis, or both. For work Tampa Electric intends to conduct itself, the company shall describe the proposed work and a schedule for completion to EPA, in writing, at least 90 days prior to the date on which Tampa Electric intends to start such work, including an explanation of why the proposed work meets all the requirements of this Subparagraph. Unless EPA objects to the proposed work on the grounds it does not comply with the requirements of this Subparagraph, Tampa Electric shall undertake and complete the work according to the proposed schedule. If Tampa Electric elects to spend some or all of the $2 million Project Dollars to finance work to be performed by other persons or organizations, the company shall provide to EPA for review and approval a plan that describes the work to be performed, the persons or organizations conducting the work, the schedule for its completion, the schedule for Tampa Electric s payments, and an explanation of why the proposed payment(s) meets all the requirements of this Subparagraph. The plan shall be provided to EPA at least 90 days prior to the date on which Tampa Electric will begin transferring the money to finance such work. All payments to persons or organizations under such a plan shall be completed by Tampa Electric no later than June 30, 2002. Before Tampa Electric makes such payments for the benefit of any person or organization carrying out work under this Paragraph, Tampa Electric shall secure a written, signed commitment from such person to provide Tampa Electric and EPA with the results of the work.

C. Additional NO_x Reductions Project(s).

(1) General Requirement. Tampa Electric shall expend the remainder of the Project Dollars required under this Consent Decree to: (i) demonstrate innovative NO_x control technologies on any of its Units or boilers at Gannon or Big Bend not Shutdown or on Reserve / Standby; and/or (ii) reduce the NO_x Emission Rate for any Big Bend coal-combusting Unit below the lowest rate otherwise applicable to it under this Consent Decree.

(2) For any Project(s) at Gannon. If Tampa Electric elects to undertake a project on an eligible Gannon Unit(s) to demonstrate any innovative NO_x control technology, within six months after entry of this Consent Decree Tampa Electric shall submit a plan to EPA, for review and approval, which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. . EPA shall complete its review of this plan within 60 days after receipt. If such project is approved, Tampa Electric shall complete installation of the technology no later than December 31, 2004 as part of the Re-Powering of such Units; provided, however, that nothing in this Paragraph

alters Tampa Electric s obligation under Paragraph 26 of this Consent Decree.

(3) For any Project(s) at Big Bend. At least three (3) years prior to the date on which the expenditure of any Project Dollars is to commence on Big Bend under this Subparagraph C, Tampa Electric shall submit a plan to EPA for review and approval which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. If EPA approves the projects contained in the plan, Tampa Electric shall implement the project(s). Projects that would demonstrate innovative NO_x control technology or reduce the NO_x Emission Rate for any Big Bend coal-fired or Re-Powered Unit shall be operating and achieving reductions or demonstrating the performance of the innovative technology, as applicable, not later than May 1, 2010.

(4) Follow-up Report(s). Within sixty (60) days following the implementation of each EPA-approved project, Tampa Electric shall submit to EPA a report that documents the date that all aspects of the project were implemented, Tampa Electric s results in implementing the project, including the emission reductions or other environmental benefits

achieved, and the Project Dollars expended by Tampa Electric in implementing the project.

VIII. STIPULATED PENALTIES

53. For purposes of this Consent Decree, within thirty days after written demand from the United States, and subject to the provisions of Sections X (Force Majeure) and XI (Dispute Resolution), Tampa Electric shall pay the following stipulated penalties to the United States for each failure by Tampa Electric to comply with the terms of this Consent Decree.

A. For failure to pay timely the civil penalty as specified in Section VI of this Consent Decree, $10,000 per day.

B. For all violations of a 24 hour Emission Rate (1) Less than 5% in excess of limit: $4,000 per day, per violation; (2) more than 5% but less than 10% in excess of limit: $9,000 per day per violation; (3) equal to or greater than 10% in excess of limit: $27,500 per day, per violation

C. For all violations of 30-day rolling average Emission Rates (1) Less than 5% in excess of limit: $150 per day per violation; (2) more than 5% but less than 10% in excess of limit: $300 per day per violation; (3) equal to or greater than 10% in excess of limit: $800 per day per violation. Violation of an Emission Rate that is based on a 30 day rolling average is a violation on every day of the 30 day period on which the average is based . Where a violation of a 30 day rolling monthly average Emission Rate (for the same pollutant and from the same

source) recurs within periods less than 30 days, Tampa Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

D. For all violations of a 95% removal efficiency requirement (1) For removal efficiency less than 95% but greater than or equal to 94%, $4,000 per day, per violation; (2) for removal efficiency less than 94% but greater than or equal to 91%, $9,000 per day, per violation; (3) for removal efficiency less than 91%, $27,500 per day, per violation. For all violations of a 93% removal efficiency requirement (1) For removal efficiency less than 93% but greater than or equal to 92%, $4,000 per day, per violation; (2) for removal efficiency less than 92% but greater than or equal to 90%, $9,000 per day, per violation; (3) for removal efficiency less than 90%, $27,500 per day, per violation;

E. Violation of deadlines for Shutdown of boilers or Units or megawatt capacity $27,500 per day, per violation.

F. Failure to apply for the permits required by Paragraphs 26, 27, 34, 38, and 42 $1,000 per day, per violation.

G. Failure to implement the recommendations of the PM BACT Analysis or the PM optimization study by May 1, 2004 $5,000 per day, per violation for first 30 days; $15,000 per day, per violation, for next 30 days; $27,500 per day, per violation, thereafter.

H. Failure to commence combustion optimization at Big Bend Units 1, 2, or 3 on or before May 30, 2003 as required by Paragraph 35, $10,000 per day, per violation.

I. Failure to operate the scrubbers at Big Bend Units 1, 2, or 3 on any day except as permitted by Paragraphs 29, 30, or 31, $27,500 per day, per violation.

J. Failure to submit quarterly progress and monitoring report $100 per day, per violation, for first ten days late, and $500 per day for each day thereafter.

K. Failure to complete timely any action or payment required by or established under Subparagraph 52(B) (Performance of Air Chemistry Work in Tampa Bay Estuary), $5,000 per day, per violation

L. Failure to perform NO_x reduction or demonstration project(s), by the deadline(s) established in Subparagraph 52.C (Additional NO_x Reductions Project(s)), $10,000 per day, per violation;

M. For failure to spend at least the number of Project Dollars required by this Consent Decree by date specified in Paragraph 50, $5,000 per day, per violation;

N. Violation of any Consent Decree prohibition on use of allowances as provided in Paragraph 46 three times the market value of the improperly used allowance as measured at the time of the improper use.

54. Should Tampa Electric dispute its obligation to pay part or all of a stipulated penalty demanded by the United States, it may avoid the imposition of a separate stipulated penalty for the failure to pay the disputed penalty by depositing the disputed amount in a commercial escrow account pending resolution of the matter and by invoking the Dispute Resolution provisions of this Consent Decree within the time provided in this Section VIII of the Consent Decree for payment of the disputed penalty. If the dispute is thereafter resolved in Tampa Electric's favor, the escrowed amount plus accrued interest

shall be returned to Tampa Electric. If the dispute is resolved in favor of the United States, it shall be entitled to the escrowed amount determined to be due by the Court, plus accrued interest. The balance in the escrow account, if any, shall be returned to Tampa Electric.

55. The United States reserves the right to pursue any other remedies to which it is entitled, including, but not limited to, a new civil enforcement action and additional injunctive relief for Tampa Electric's violations of this Consent Decree. If the United States elects to seek civil or contempt penalties after having collected stipulated penalties for the same violation, any further penalty awarded shall be reduced by the amount of the stipulated penalty timely paid or escrowed by Tampa Electric. Tampa Electric shall not be required to remit any stipulated penalty to the United States that is disputed in compliance with Part XI of this Consent Decree until the dispute is resolved in favor of the United States. However, nothing in this Paragraph shall be construed to cease the accrual of the stipulated penalties until the dispute is resolved.

IX. RIGHT OF ENTRY

56. Any authorized representative of EPA or an appropriate state agency, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of Tampa Electric's plants identified herein at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and inspecting and copying all records maintained by Tampa Electric required by this Consent Decree. Tampa Electric shall retain such records for a

period of twelve (12) years from the date of entry of this Consent Decree. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Tampa Electric s facilities under Section 114 of the Act, 42 U.S.C. § 7414.

X. FORCE MAJEURE

57. If any event occurs which causes or may cause a delay in complying with any provision of this Consent Decree, Tampa Electric shall notify the United States in writing as soon as practicable, but in no event later than seven (7) business days following the date Tampa Electric first knew, or within ten (10) business days following the date Tampa Electric should have known by the exercise of due diligence, that the event caused or may cause such delay. In this notice Tampa Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, the measures taken or to be taken by Tampa Electric to prevent or minimize the delay, and the schedule by which those measures will be implemented. Tampa Electric shall adopt all reasonable measures to avoid or minimize such delays.

58. Failure by Tampa Electric to comply with the notice requirements of Paragraph 57 shall render this Section X voidable by the United States as to the specific event for which Tampa Electric has failed to comply with such notice requirement. If voided, the provisions of this Section shall have no effect as to the particular event involved.

59. The United States shall notify Tampa Electric in writing regarding Tampa Electric's claim of a delay in performance within (15) fifteen business days of receipt of the Force

Majeure notice provided under Paragraph 57. If the United States agrees that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay through the exercise of due diligence, the parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay for a period equivalent to the delay actually caused by such circumstances. Such stipulation shall be filed as a modification to this Consent Decree in order to be effective. Tampa Electric shall not be liable for stipulated penalties for the period of any such delay.

60. If the United States does not accept Tampa Electric's claim of a delay in performance, to avoid the imposition of stipulated penalties Tampa Electric must submit the matter to this Court for resolution by filing a petition for determination. Once Tampa Electric has submitted the matter, the United States shall have fifteen business days to file its response. If Tampa Electric submits the matter to this Court for resolution, and the Court determines that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay by the exercise of due diligence, Tampa Electric shall be excused as to that event(s) and delay (including stipulated penalties otherwise applicable), but only for the period of time equivalent to the delay caused by such circumstances.

61. Tampa Electric shall bear the burden of proving that any delay in performance of any requirement of this Consent Decree was caused by or will be caused by circumstances

beyond its control, including any entity controlled by it, and that Tampa Electric could not have prevented the delay by the exercise of due diligence. Tampa Electric shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

62. Unanticipated or increased costs or expenses associated with the performance of Tampa Electric's obligations under this Consent Decree shall not constitute circumstances beyond the control of Tampa Electric or serve as a basis for an extension of time under this Section. However, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure event where the failure of the permitting authority to act is beyond the control of Tampa Electric and Tampa Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting appeals of any allegedly unlawful terms and conditions imposed by the permitting authority in an expeditious fashion.

63. The parties agree that, depending upon the circumstances related to an event and Tampa Electric s response to such circumstances, the kinds of events listed below could also qualify as Force Majeure events within the meaning of this Section X of the Consent Decree: Construction, labor, or equipment delays; natural gas and gas transportation availability delays;acts of God; and the failure of an innovative technology approved under Paragraph 26.B and 52.C.

64. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of Tampa Electric delivering a notice pursuant to this Section or the parties' inability to reach agreement on a dispute under this Part.

65. As part of the resolution of any matter submitted to this Court under this Section, the parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by this Court. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XI. DISPUTE RESOLUTION

66. The dispute resolution procedure provided by this Section XI shall be available to resolve all disputes arising under this Consent Decree, except as provided in Section X regarding Force Majeure, or in this Section XI, provided that the party making such application has made a good faith attempt to resolve the matter with the other party.

67. The dispute resolution procedure required herein shall be invoked by one party to this Consent Decree giving written notice to another advising of a dispute pursuant to this Section XI. The notice shall describe the nature of the dispute and shall state the noticing party's position with regard to such dispute. The party receiving such a notice shall acknowledge receipt of the notice, and the parties shall expeditiously schedule a meeting

to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

68. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between representatives of the United States and Tampa Electric unless the parties' representatives agree to shorten or extend this period.

69. If the parties are unable to reach agreement during the informal negotiation period, the United States shall provide Tampa Electric with a written summary of its position regarding the dispute. The written position provided by the United States shall be considered binding unless, within thirty (30) calendar days thereafter, Tampa Electric files with this Court a petition which describes the nature of the dispute and seeks resolution. The United States may respond to the petition within forty-five (45) calendar days of filing.

70. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the parties to the dispute.

71. This Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of invocation of this Section or the parties' inability to reach agreement.

72. As part of the resolution of any dispute under this Section, in appropriate circumstances the parties may agree, or this Court may order, an extension or modification of the schedule for completion of work under this Consent Decree to account for the delay that

occurred as a result of dispute resolution. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

73. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes; provided, however, that the United States and Tampa Electric reserve their rights to argue for what the applicable standard of law should be for resolving any particular dispute. Notwithstanding the preceding sentence of this Paragraph, as to disputes arising under Paragraph 32, the Court shall sustain the position of the United States as to the BACT Analysis recommendations and the optimization study measures that should be installed and implemented, unless Tampa Electric demonstrates that the position of the United States is arbitrary or capricious.

XII. GENERAL PROVISIONS

74. Effect of Settlement. This Consent Decree is not a permit; compliance with its terms does not guarantee compliance with all applicable Federal, State or Local laws or regulations.

75. Satisfaction of all of the requirements of this Consent Decree constitutes full settlement of and shall resolve and release Tampa Electric from all civil liability of Tampa Electric to the United States for the claims referred to in Paragraphs 43 and 44 of this Consent Decree. This Consent Decree does not apply to any claim(s) of alleged criminal liability, which are reserved.

76. In any subsequent administrative or judicial action initiated by the United States for

injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Tampa Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim splitting, or other defense based upon any contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the enforceability of the Resolution of Claims provisions of Paragraphs 43 and 44 of this Consent Decree..

77. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Tampa Electric of its obligation to comply with all applicable Federal, State and Local laws and regulations. Subject to Paragraph 43 and 44, nothing contained in this Consent Decree shall be construed to prevent or limit the United States' rights to obtain penalties or injunctive relief under the Clean Air Act or other federal, state or local statutes or regulations.

78. Third Parties. This Consent Decree does not limit, enlarge or affect the rights of any party to this Consent Decree as against any third parties.

79. Costs. Each party to this action shall bear its own costs and attorneys' fees.

80. Public Documents. All information and documents submitted by Tampa Electric to the United States pursuant to this Consent Decree shall be subject to public inspection, unless subject to legal privileges or protection or identified and supported as business confidential by Tampa Electric in accordance with 40 C.F.R. Part 2.

81. Public Comments. The parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the requirements of 28 C.F.R. §

50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate.

82. Notice. Unless otherwise provided herein, notifications to or communications with the United States or Tampa Electric shall be deemed submitted on the date they are postmarked and sent either by overnight mail, return receipt requested, or by certified or registered mail, return receipt requested. Except as otherwise provided herein, when written notification to or communication with the United States, EPA, or Tampa Electric is required by the terms of this Consent Decree, it shall be addressed as follows:

As to the United States of America:

For U.S. DOJ

Chief
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06932

Whitney L. Schmidt
Coordinator, Affirmative Civil Enforcement Program
Office of the United States Attorney
Middle District of Florida
400 N. Tampa Street
Tampa, FL 33602

For U.S. EPA

Director, Air Enforcement Division

Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region IV
61 Forsyth Street, S.E.
Atlanta, GA 30303

As to Tampa Electric:

Sheila M. McDevitt
General Counsel
Tampa Electric Company
P.O. Box 111
Tampa, FL 333601-0111

83. Any party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

84. Modification. Except as otherwise allowed by law, there shall be no modification of this Consent Decree without written approval by the United States and Tampa Electric, and approval of such modification by the Court.

85. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, or modification. During the term of this Consent Decree, any party may apply

to the Court for any relief necessary to construe or effectuate this Consent Decree.

86. Complete Agreement. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the parties with respect to the settlement embodied in this Consent Decree. The parties acknowledge that there are no representations, agreements or understandings relating to the settlement other than those expressly contained in this Consent Decree. An Appendix is attached to and incorporated into this Consent Decree by this reference.

XIII. TERMINATION

87. Except as provided in Paragraphs 43, 44, and 45 (involving resolution of claims), this Consent Decree shall be subject to termination upon motion by either party after Tampa Electric satisfies all requirements of this Consent Decree, including payment of all stipulated penalties that may be due, installation of control technology systems as specified herein, the receipt of all permits specified herein, securing valid Title V Permits for Gannon and Big Bend that incorporate all emission and fuel limits from this Consent Decree as well as all operational limits established under this Consent Decree, and the submission of all final reports indicating satisfaction of the requirements for implementation of all acts called for under Part VII of this Consent Decree.

88. If Tampa Electric believes it has achieved compliance with the requirements of this Consent Decree, then Tampa Electric shall so certify to the United States. Unless the United States objects in writing with specific reasons within 60 days of receipt of Tampa Electric s certification, the Court shall order that this Consent Decree be terminated on

Tampa Electric's motion. If the United States objects to Tampa Electric's certification, then the matter shall be submitted to the Court for resolution under Section XI of this Consent Decree. In such case, Tampa Electric shall bear the burden of proving that this Consent Decree should be terminated.

SO ORDERED, THIS _____ DAY OF _____ 2000.

_____

UNITED STATES DISTRICT JUDGE

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

THROUGH ITS UNDERSIGNED REPRESENTATIVES, THE UNITED STATES AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE:

FOR PLAINTIFF
UNITED STATES OF AMERICA:

_____ Date: _____

Lois J. Schiffer
Assistant Attorney General
Environment and Natural Resources
Division
United States Department of Justice

_____

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Donna A. Bucella
United States Attorney for the
Middle District of Florida

By:_____
Whitney L. Schmidt
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United States Attorney s Office
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Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

Steven A. Herman
Assistant Administrator for Office of Enforcement
and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

Bruce Buckheit
Director

Gregory Jaffe
Senior Enforcement Counsel

Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

John H. Hankinson
Regional Administrator
U.S. Environmental Protection Agency (Region IV)
Atlanta, Georgia

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

THROUGH ITS UNDERSIGNED REPRESENTATIVES, TAMPA ELECTRIC COMPANY AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE

FOR TAMPA ELECTRIC COMPANY

_____ Date: _____

John B. Ramil
President
Tampa Electric Company

_____

Sheila M. McDevitt
General Counsel
Tampa Electric Company

Friday, Barbara

To: gbriggs@tecoenergy.com; rcalderon@tecoenergy.com; evance@tecoenergy.com; 'tdavis@ectinc.com'; Waters, Jason; campbell@epchc.org

Cc: Koerner, Jeff

Subject: FINAL Title V Permit Renewal No.: 0570040-023-AV - Tampa Electric Company - H.L. Culbreath Bayside Power Station

Attached for your records is a zip file which contains the FINAL Title V Permit Renewal and associated documents.

If I may be of further assistance, please feel free to contact me.

Barbara J. Friday
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