Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

February 5, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Karen Sheffield, General Manager
Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619

Re: Project No. 0570040-013-AC
Draft Permit No. PSD-FL-301
Draft PSD Permit for the Bayside Power Station
(Gannon Re-Powering Project)

Dear Ms. Sheffield:

Enclosed is one copy of the Draft Permit to re-power the existing Gannon power plant located on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and consist of seven new gas-fired combined cycle gas turbine units. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

The "Public Notice of Intent to Issue Permit" must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to the Administrator of the New Source Review Section, A. A. Linero, at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

C. H. Fancy, Chief
Bureau of Air Regulation

CHF/AAL/jfk

Enclosures

7009 3400 0000 1449 4031

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

Article Sent To:
Ms. Karen Sheffield

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Ms. Karen Sheffield
Street, Apt. No., or PO Box No.
Port Sutton Road
City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- 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:

Ms. Karen Sheffield
General Manager
Tampa Electric Company
Bayside Power Station
Port Sutton Road
Tampa, FL 33619

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 2/7
C. Signature
X [signature]
☐ Agent
☐ Addressee
D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number (Copy from service label) 7009 3400 0000 1449 4031

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT

PERMITTEE

Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619

Project No.	0570040-013-AC
Draft Permit No.	PSD-FL-301
Facility ID No.	0570040
SIC No.	4911

PROJECT DESCRIPTION

The Tampa Electric Company (TEC) owns and operates the F.J. Gannon Station located on Tampa's Port Sutton Road in Hillsborough County, Florida. TEC proposes to re-power the existing Gannon Station with seven new combined cycle gas turbines in accordance with the DEP/TEC Consent Final Judgment signed in December of 1999 and with the EPA/TEC Consent Decree signed in February of 2000. Each unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. Steam from three new combined cycle units (Bayside Units 1A, 1B, and 1C) will re-power existing Gannon steam-electric turbine No. 5 (nameplate rating of 239 MW). Steam from four new combined cycle units (Bayside Units 2A, 2B, 2C, and 2D) will re-power existing Gannon steam-electric turbine No. 6 (nameplate rating of 414 MW). An existing 14 MW simple cycle gas turbine will remain on site. All existing coal-fired boilers (Gannon Units 1 – 6) will be shut down prior to January 1, 2005. The re-powered plant will have an electrical production capacity of approximately 1700 MW.

The project will result in significant net increases in actual emissions of CO and VOC. Based on EPA Region 4's interpretation of netting for this project, it is also significant for emissions PM/PM_{10}. The Best Available Control Technology (BACT) for each of these pollutants is determined to be the efficient combustion of clean fuels. Pipeline-quality natural gas is the primary fuel and very low sulfur distillate oil (< 0.05% sulfur by weight) is the backup fuel. Each unit may fire may fire up to 875 hours of distillate oil per year, but only if natural gas cannot be fired in the unit. The state and federal settlement agreements specified installation of the SCR systems. NOx emissions are controlled by an SCR system combined with dry low-NOx combustion technology when firing natural gas and combined with water injection when firing oil. Each combined cycle unit will have CO and NOx continuous emissions monitoring systems to demonstrate compliance. The CO emissions standards serve as surrogate standards for emissions of PM/PM_{10} and VOC.

After shutdown of the coal-fired units, it is estimated that the Bayside project will reduce *actual* emissions of nitrogen oxides by more than 28,000 tons per year, particulate matter by more than 1000 tons per year, and sulfur dioxide by more than 60,000 tons per year. Although not specifically required for each pollutant, the emissions standards specified in the Draft Permit for CO, NOx, PM/PM_{10}, SO_2, and VOC represent BACT-level controls. In addition, the CO and NOx emissions monitors will provide a continuous demonstration of compliance with the standards and efficient combustion of each unit.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

Jeffery F. Koerner
02-01-01

Jeffery F. Koerner, P.E.
Registration Number: 49441
(Date)

DARM/BAR - New Source Review Section
Florida Department of Environmental Protection

In the Matter of an
Application for Air Permit by:

Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619
Authorized Representative:
Ms. Karen Sheffield, General Manager

Project No. 0570040-013-AC
Draft Permit No. PSD-FL-301
Bayside Power Station
Hillsborough County, Florida

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. The applicant, Tampa Electric Company, applied on September 21, 2000 to the Department for a permit to re-power the existing F.J. Gannon power plant located on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station. The Draft Permit requires the shutdown of existing coal-fired units and authorizes the construction of seven new combined cycle gas turbine units. The proposed permit includes determinations of the Best Available Control Technology (BACT) for emissions of carbon monoxide, particulate matter, and volatile organic compounds. As agreed to by Tampa Electric Company, the proposed permit defers the determination of the Maximum Available Control Technology (MACT) for hazardous air pollutants (HAP) until after a unit is tested for HAP emissions.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) and (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in section 120.542(2), F.S. and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2/5/01 to the person(s) listed:

Ms. Karen Sheffield, Bayside*
Mr. Patrick Shell, Bayside
Ms. Cindy Barringer, Bayside
Mr. Tom Davis, ECT
Chair, Hillsborough County BCC
Mr. Jerry Campbell, HEPC
Mr. Bill Thomas, SWD
Mr. John Notar, NPS
Mr. Winston Smith, EPA Region 4

Clerk Stamp

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

Charlotte Hayes 2/5/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Tampa Electric Company
Bayside Power Station
(Gannon Re-Powering Project)

Project No. 0570040-013-AC
Draft Permit PSD-FL-301

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Tampa Electric Company to re-power the existing F. J. Gannon power plant on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and will have an electrical production capacity of approximately 1740 MW. The applicant's authorized representative is Ms. Karen Sheffield, the General Manager of the Bayside Power Station. The applicant's mailing address is Bayside Power Station, Port Sutton Road, Tampa, FL 33619.

In accordance with state and federal settlement agreements, the applicant proposes to re-power the existing Gannon Station with seven new combined cycle General Electric Model PG7241(FA) gas turbines. All existing coal-fired boilers will be shut down before January 1, 2005. The overall thermal efficiency of the plant is predicted to increase from approximately 30% to 55%. It is estimated that the Bayside project will reduce actual emissions of nitrogen oxides (NOx) by more than 28,000 tons per year, particulate matter by more than 1000 tons per year, and sulfur dioxide by more than 60,000 tons per year. Although not specifically required by rule for each pollutant, the proposed permit represents current Best Available Control Technology (BACT) measures for combined cycle gas turbines to control emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). The proposed permit also requires the continuous monitoring of CO and NOx emissions.

The project results in smaller, but significant increases in emissions of CO and VOC. Based on EPA Region 4's interpretation of netting for this project, it is also significant for emissions of PM/PM_{10}. Therefore, the project is subject to review in accordance with Rule 62-212.400, F.A.C., the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, and BACT determinations are required for each significant pollutant. The Department determined BACT controls for the emissions of CO, PM/PM_{10}, and VOC to be the efficient combustion of clean fuels. Pipeline-quality natural gas is the primary fuel and very low sulfur distillate oil (less than 0.05% sulfur by weight) is the backup fuel. Each unit may fire may fire up to 875 hours of distillate oil per year, but only if natural gas cannot be fired. To reduce emissions of nitrogen oxides (NOx), each combined cycle unit incorporates dry low-NOx combustion technology when firing natural gas and water injection when firing oil. Pursuant to the state and federal settlement agreements, a Selective Catalytic Reduction (SCR) system for each unit is required to further reduce NOx emissions. As agreed to by the applicant, the proposed permit defers the determination of the Maximum Available Control Technology (MACT) for hazardous air pollutants (HAP) until after a unit is tested for HAP emissions.

The applicant performed an air quality analysis in accordance with the Department's PSD requirements in Rule 62-212.400, F.A.C. Significant net increases in actual emissions were predicted for carbon monoxide and volatile organic compounds. The Department reviewed the applicant's analysis and modeling files. The ambient impact analysis predicted that emissions from the project would have an insignificant impact on Class II areas. Except for six national parks and wilderness areas, all of Florida is designated as a Class II area. No Class I significant impact levels have been defined for carbon monoxide or volatile organic compounds (ozone). The analysis also indicated that emissions from the project will not significantly contribute to or cause a violation of any state or federal ambient air quality standard when evaluated independently.

The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection	Dept. of Environmental Protection	Hillsborough County Environmental
Bureau of Air Regulation	Southwest District Office	Protection Commission
New Source Review Section	Air Resources	Air Management Division
111 S. Magnolia Drive, Suite 4	3804 Coconut Palm Drive	1410 North 21 Street
Tallahassee, FL 32301	Tampa, FL 33619-8218	Tampa, FL 33605
Telephone: 850/488-0114	Telephone: 813/744-6100	Telephone: 813/272-5530
Fax: 850/922-6979	Fax: 813/744-6084	Fax: 813/272-5605

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. Key documents may be viewed at www.dep.state.fl.us/air/permitting and clicking on TEC Bayside.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION
(Including Draft BACT and MACT Determinations)

Project No. 0570040-013-AC
Draft Permit No. PSD-FL-301

Tampa Electric Company

Bayside Power Station

(Gannon Re-powering Project)

ARMS Facility ID No. 0570040
Emissions Units 001 - 027

Hillsborough County

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

February 1, 2001

{Filename: 301d TEPD.DOC}

TABLE OF CONTENTS

This document describes the overall project, rule applicability, draft determinations of Best Available Control Technology, emissions standards, analysis of air quality impacts, and makes a preliminary determination. It is organized in the following sections:

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Tampa Electric Company – Bayside Station
Port Sutton Road
Tampa, FL 33619

Authorized Representative:
Karen Sheffield, General Manager

1.2 Processing Schedule

09/21/00	Department received the application for a PSD air pollution construction permit.
09/27/00	Department mailed copies to EPA Region 4 and the National Park Service.
10/16/00	Meeting with TEC and Department. Department requested additional information (#1).
10/19/00	Department received written comments from Hillsborough EPC.
11/15/00	Department received written comments from Hillsborough EPC.
11/18/00	Department received additional information (#1).
12/13/00	Meeting between TEC and Hillsborough EPC (Department attended by teleconference).
12/15/00	Department requested additional information (#2).
12/15/00	Department received written comments from EPA Region 4 office.
12/26/00	Department received additional information (#2). Application deemed complete.
12/27/00	Teleconference with TEC, EPA Region 4, and Department.
01/11/01	Department received written responses from TEC to Hillsborough EPC's verbal comments made during the 12/13/00 meeting.
01/12/01	Meeting between TEC and Department (Hillsborough EPC attended by teleconference). Department received TEC's revised netting analysis.

01/19/01 Department received TEC's comments on remaining issues.

01/26/01 Department received TEC information regarding CO emissions from coal fired boilers.

1.3 Facility Description and Location

When complete, the new Bayside Station will consist of seven new 170 MW combined cycle gas turbines, an existing 14 MW simple cycle gas turbine, and distillate oil storage. Steam from three new combined cycle units (Bayside Unit 1) will re-power existing Gannon steam-electric turbine No. 5 (nameplate rating of 239 MW). Steam from four new combined cycle units (Bayside Unit 2) will re-power existing Gannon steam-electric turbine No. 6 (nameplate rating of 414 MW). All coal-fired boilers (Gannon Units 1-6) will be shut down prior to January 1, 2005. The re-powered plant will have a nominal electrical production capacity of approximately 1742 MW. The new plant will be located within the existing Gannon plant boundaries on Port Sutton Road in Tampa, Florida. The UTM coordinates are Zone 17, 360.00 km E, 3087.50 km N and the map coordinates are Latitude 27° 54' 18", Longitude 82° 25' 21".

1.4 Standard Industrial Classification Code (SIC)

Industry Group No. 49, Electric, Gas, and Sanitary Services
Industry No. 4911, Electric Services

1.5 Regulatory Categories

PSD: The re-powered plant is considered a fossil fuel fired steam electric plant of more than 250 mmBTU per hour of heat input with emissions of at least one regulated pollutant exceeding 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Therefore, the facility is a major source of air pollution with respect to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality.

Title V: The re-powered plant is a Title V major source of air pollution because potential emissions of at least one regulated pollutant exceed 100 tons per year.

Title IV: Gas turbines at the re-powered plant are subject to the Title IV acid rain provisions.

Title III: Based on available information, the re-powered plant is potentially a major source of hazardous air pollutants (HAPs).

NESHAP: No emissions units at the re-powered plant are identified as being subject to any National Emissions Standards for Hazardous Air Pollutant (NESHAP) in 40 CFR 61 or 40 CFR 63.

NSPS: The gas turbines (Subpart GG) and the distillate oil storage tank (Subpart Kb) at the re-powered plant are subject to the New Source Performance Standards (NSPS) specified in 40 CFR 60.

2. PROPOSED PROJECT

2.1 Project Description

The Tampa Electric Company (TEC) owns and operates the F.J. Gannon Station located on Port Sutton Road in Tampa, Hillsborough County, Florida. TEC proposes to re-power the existing Gannon Station with seven new combined cycle gas turbines in accordance with the DEP/TEC Consent Final Judgment signed in December of 1999 and with the EPA/TEC Consent Decree signed in February of 2000. Each unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. Steam from three new combined cycle units (Bayside Units 1A, 1B, and 1C) will re-power existing Gannon steam-electric turbine No. 5 (nameplate rating of 239 MW). Steam from four new combined cycle units (Bayside Units 2A, 2B, 2C, and 2D) will re-power existing Gannon steam-electric turbine No. 6 (nameplate rating of 414 MW). An existing 14 MW simple cycle gas turbine will remain on site. All existing coal-fired boilers (Gannon Units 1 – 6) will be shut down prior to January 1, 2005. The re-powered plant will have a nominal electrical production capacity of approximately 1742 MW. See Attachment A for an artist's rendering of the new plant.

2.2 Potential Emissions

The applicant estimates that operation of the new gas turbines would result in potential pollutant emissions of the following amounts: 989.7 tons of carbon monoxide per year, 1018.2 tons nitrogen oxides per year, 1.07 tons of lead per year, 721.4 tons particulate matter per year, 96.7 tons of sulfuric acid mist per year, 576.3 tons sulfur dioxide per year, 99.6 tons volatile organic compounds per year, 4 pounds of beryllium per year, and 14 pounds of mercury per year. Emissions decreases from the shutdown of Gannon Units 5 and 6 are discussed later in the netting analysis covered in Section 3.

2.3 Applicant's Proposed Emissions Standards and Controls

The following table summarizes the applicant's requested emissions standards and proposed control equipment for each combined cycle gas turbine.

Table 2.3 Applicant's Proposed Emissions Standards and Controls for Gas Turbines

Pollutant	Control Option	Emission Standards		
		Natural Gas	Distillate Oil	Units
CO	Combustion Design	7.8	30.3	ppmvd @ 15% O_2
NOx	Dry Low-NOx Combustion and Fuel Limitations	3.5	16.4	ppmvd @ 15% O_2
PM/PM_{10}	Combustion Design and Fuel Specifications	10%	10%	opacity
SAM/SO_2	Fuel Specifications	2.0 NA	NA 0.05%	grains/ 100 scf gas sulfur by weight
VOC	Combustion Design	1.3	3.0	ppmvd @ 15% O_2

3. RULE APPLICABILITY AND THE PSD PRECONSTRUCTION REVIEW PROCESS

3.1 State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following state rules and regulations of the Florida Administrative Code.

Citation	Description
Chapter 62-4	Permitting Requirements
Chapter 62-204	Ambient Air Quality Protection and Standards, PSD Increments, and Federal Regulations Adopted by Reference
Chapter 62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
Chapter 62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
Chapter 62-213	Operation Permits for Major Sources of Air Pollution
Chapter 62-214	Acid Rain Program Requirements
Chapter 62-296	Emission Limiting Standards
Chapter 62-297	Test Requirements, Test Methods, Supplementary Test Procedures, Capture Efficiency Test Procedures, Continuous Emissions Monitoring Specifications, and Alternate Sampling Procedures

{Note: Chapter 62-17, F.A.C., Electrical Power Plant Siting, does not apply to this project because there will be no expansion in steam electric generating capacity. (Memo from the PPS Office dated 10/11/00)}

3.2 Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Citation	Description
40 CFR 51.166	Submittal of Implementation Plans - Prevention of Significant Deterioration of Air Quality
40 CFR 52.21	Approval of Implementation Plans - Prevention of Significant Deterioration of Air Quality
40 CFR 60	New Source Performance Standards (NSPS)
	NSPS - Subpart A, General Provisions for NSPS Sources
	NSPS - Subpart GG, Stationary Gas Turbines
	NSPS - Subpart Kb, Volatile Organic (Including Petroleum) Liquid Storage Vessels
	NSPS - Applicable Appendices
40 CFR 72	Acid Rain - Permits Regulation
40 CFR 73	Acid Rain - Sulfur Dioxide Allowance System
40 CFR 75	Acid Rain - Continuous Emissions Monitoring
40 CFR 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
40 CFR 77	Acid Rain - Excess Emissions

{Permitting Note: Acid rain requirements will be included in the Title V air operation permit.}

3.3 Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. and approved by EPA in the State Implementation Plan. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants.

3.4 Description of PSD Preconstruction Review Requirements

PSD preconstruction review consists of two parts. The first part requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The applicant must satisfactorily demonstrate that potential project emissions will not significantly contribute to or cause a violation of any ambient air quality standards and will have an insignificant impact on Class I and Class II Areas.

The second part requires the Department to establish the Best Available Control Technology (BACT) for each pollutant emitted in excess of the PSD Significant Emission Rates. The applicant reviews current control technologies and techniques for similar projects and proposes control options and emissions standards for the project. The Department reviews the information provided by the applicant with all other available information and makes a determination of the Best Available Control Technology (BACT) for each "significant" regulated pollutant. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. The Department shall also give consideration to:

- Any EPA determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

The BACT evaluation must be performed for each emissions unit and pollutant under consideration. BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards regulated by 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention. These approaches are consistent with EPA's consideration of environmental impacts and strategies for pollution prevention.

3.5 Description of "Netting"

As described in Rule 62-212.400(2)(e), F.A.C., the PSD regulations allow applicants to avoid preconstruction review through a concept known as "netting". Applicants may obtain enforceable reductions of actual emissions to compensate for emissions from new projects. For example, an applicant could agree to restrict operation, add improved controls, or even shutdown existing units to secure emissions decreases. If the sum of all the creditable increases and decreases in actual emissions from a project are greater than zero, there is a net emissions increase. A BACT determination is only required for each pollutant with a "significant" net emissions increase greater than the applicable PSD significant emission rate listed in Table 212.400-2, F.A.C.

3.6 Project Applicability

The Bayside project is located in Hillsborough County, an area that is currently in attainment (or designated as "maintenance" or "unclassifiable") for each pollutant subject to a National Ambient Air Quality Standard (NAAQS). The re-powered electrical generating plant is considered a fossil fuel fired steam electric plant of more than 250 mmBTU per hour of heat input, which is one of the 28 PSD industries listed in Table 62-212.400-1, F.A.C. Because emissions of at least one regulated pollutant exceed 100 tons per year, this facility is a major source of air pollution with respect to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD).

The initial application identified the project as subject to PSD review with a BACT determination required for VOC emissions only. This was based on an initial netting analysis considering the full emissions decreases from the shutdown of the coal-fired boilers for Gannon Units 5 and 6. Subsequent comments from EPA Region 4 required a revised netting analysis that indicated the project requires BACT determinations for CO, PM/PM_{10}, and VOC emissions. Both analyses are presented below.

3.7 Applicant's Initial Netting Analysis

Re-powering the existing steam-electrical generators with gas turbines requires shutdown of the coal-fired boilers for Gannon Units 5 and 6. The applicant believes that the emissions decreases from the shutdown units can be used in a PSD netting analysis to avoid triggering BACT determinations for several pollutants. The following table summarizes the applicant's initial netting analysis that considered:

- The contemporaneous period begins in September of 1995 and ends in March of 2004.
- The Gannon Unit 5 coal-fired boiler will be shut down prior to operation of Bayside Units 1A, 1B and 1C, which results in emissions decreases.
- Bayside Units 1A, 1B and 1C begin operation in 2003, which results in emissions increases.
- The Gannon Unit 6 coal-fired boiler will be shut down prior to operation of Bayside Units 2A, 2B, 2C and 2D, which results in emissions decreases.
- Bayside Units 2A, 2B, 2C and 2D begin operation in 2004, which results in emissions increases.
- The analysis assumes that there will be no actual emissions increases from Gannon Units 1, 2, 3, and 4 while the project is being completed.
- No other projects have been identified during the contemporaneous periods that would result in emissions increases.

Table 3.7 Summary of Applicant's Initial Netting Analysis

Pollutant	Gannon Unit 5 TPY	Bayside Unit 1 TPY	Gannon Unit 6 TPY	Bayside Unit 2 TPY	Net Emissions TPY	PSD SER* TPY	BACT Required? Yes/No
CO	-2055.5	+424.2	-3334.1	+565.5	-4399.9	100	No
NO_x	-4746.5	+436.4	-10,931.5	+581.8	-14,659.8	40	No
Pb	-3.7	+0.5	-5.9	+0.6	-8.5	0.6	No
PM/PM_{10}	-234.9	+309.2	-864.8	+412.2	-378.3	25/15	No
SAM	-56.2	+41.4	-91.7	+55.3	-51.2	7	No
SO_2	-13,151.0	+247.0	-23,266.5	+329.3	-35,841.2	40	No
VOC	**-11.0**	**+42.7**	**-17.9**	**+56.9**	**+70.7**	**40**	**Yes**

* *PSD Significant Emission Rate (SER) listed in Table 62-212.400-2, F.A.C.*

As shown, the applicant identifies that the project only requires a BACT determination for VOC emissions. However, the past actual annual CO emissions for Gannon Units 5 and 6 are based on emission performance tests conducted on Gannon Unit 5 in April of 2000. TEC maintains that CO emissions have increased as a direct result of NO_x control strategies that began in 1996. The Department does not believe this claim has been proven and believes the past actual annual emissions should be based on the annual operating reports for the representative years. Gannon Unit 5 would have past actual CO emissions of 138.2 tons per year and Gannon Unit 6 would have 247.0 tons per year. Therefore, the Department believes that the re-powering project results in a net CO emissions increase of 604.5 tons per year and also requires a BACT determination for this pollutant. Although a revised netting analysis was performed, the initial netting analysis remains important because it reflects the "actual" emissions increases from the project. It is the actual emissions increases that will determine the requirements for performing the Ambient Air Quality Analysis.

3.8 Revised Netting Analysis Considering EPA Region 4 Comments

The Department questioned the appropriateness of netting because the proposed project resulted from an enforcement action concerning alleged violations of the PSD regulations. Previous EPA guidance advises that emissions decreases necessary to comply with regulatory requirements cannot be used in a netting analysis (Page A.48 of EPA's 1990 draft guidance entitled, "New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting"). However, the EPA Region 4 Office provided comments on the netting analysis on December 15, 2000. The comments regarding netting issues interpreted the EPA/TEC Consent Decree and are summarized as follows:

- TEC may use actual emissions reductions from the shutdown of the coal-fired boilers for Gannon Units 5 and 6 to net out of PSD review for the Bayside re-powering project.
- TEC should estimate past actual emissions based on the assumption that "present day" Best Available Control Technology (BACT) is installed on existing Gannon Units 5 and 6. (This will reduce the amount of past actual emissions and lower any emissions decreases resulting from the shutdown of the coal-fired boilers.)
- Any remaining emissions reductions that are not used for the Bayside re-powering project could potentially be used by TEC in a future netting analysis.

EPA Region 4 stated that the EPA/TEC Consent Decree would be modified in the near future to reflect this interpretation. These comments were repeated in a December 27, 2000 teleconference between the Department, EPA Region 4 staff, and TEC staff. In response to these comments, the Department reviewed current projects to determine "present day" BACT controls when modifying an existing coal-fired plant. The Department is processing an application to modify existing coal-fired boilers at the Indiantown Cogeneration Limited Partnership plant. Under consideration are the following controls and standards.

Table 3.8a Evaluation of "Present Day" BACT Controls

Pollutant	Emission Rates			Control Efficiency	AP-42 (Range) Control Efficiency
	Past Actual		Present Day BACT		
	lb/ton coal	lb/mmBTU	lb/mmBTU	Percent (%)	Percent (%)
CO	0.5	0.02	0.092, Good Combustion	NA	NI
NOx	31.0	1.25	0.125, SCR	90%	75 to 86%
Pb	4.2 E^{-04}	1.7 E^{-05}	1.6 E^{-05}, ESP or Baghouse	6%	NI
PM/PM_{10}	43.4	1.75	0.015, ESP or Baghouse	99%	99 to 99.9%
SAM	2.85	0.11	0.0035, Lime Spray Dryer	97%	NI
SO_2	57.0	2.30	0.142, Lime Spray Dryer	94%	> 90%
VOC	0.04	0.002	0.003, Good Combustion	NA	NI

Notes:

a. The "past actual" emission factors are based on uncontrolled AP-42 emission factors for wet bottom, wall-fired, coal fired boilers in Section 1.1. As in the application, SAM is assumed to be 0.5% of the SO_2 emission rate.

b. The "present day" BACT emission factors are based on retrofit controls for the proposed modification of coal fired boilers at the Indiantown Cogeneration Limited Partnership plant.

The Department believes that the above evaluation represents "present day" BACT for the modification of existing coal-fired boilers. Based on this information, the following table summarizes the revised netting analysis assuming that the "present day" BACT controls were installed on Gannon Units 5 and 6 during the representative years.

Table 3.8b Summary of Revised Netting Analysis Based on EPA Region 4's Comments

Pollutant	Gannon Units 5 and 6			Bayside Station	Net Emissions Change TPY	PSD SER* TPY	BACT Required? Yes/No
	Uncontrolled	Present Day BACT		Potential Emissions TPY			
	Past Actual TPY	Control Efficiency	Past Actual TPY				
CO [a]	**385.2**	**0%**	**385.2**	**989.7**	**+604.5**	**100**	**Yes**
NOx	15678.0	90%	1567.8	1018.2	-549.6	40	No
Pb	9.6	0%	9.8	1.07	-8.5	0.6	No
PM/PM_{10} [b]	**1099.7**	**84.5%**	**165.0**	**721.4**	**+556.4**	**25/15**	**Yes**
SAM [c]	148.0	35%	96.2	96.7	+0.5	7	No
SO_2	36,417.5	90%	3641.8	576.3	-3065.5	40	No
VOC	**35.4**	**0%**	**35.4**	**99.6**	**+64.2**	**40**	**Yes**

Notes:

a. The past actual annual emissions are based on the annual operating reports submitted by TEC during the representative years. TEC's past actual CO emissions in the initial netting analysis were based on an emission rate developed from a 3-hour performance test conducted on Gannon Unit 5 in April of 2000. TEC explained that the large CO emissions increases resulted from NOx control strategies implemented in 1996. Although such strategies could increase CO emissions, the Department believes the data presented is insufficient to determine the extent of emissions or to estimate annual emissions. Although TEC disagreed with the Department, they did consent to provide a CO BACT determination and control equipment cost estimates for the combined cycle gas turbines.

b. The "84.5%" particulate control efficiency reflects the additional control necessary to achieve an overall 99% efficiency as "present day" BACT control considering the existing ESPs. It was assumed the existing ESPs achieved 94.5% control to meet the particulate matter standard of 0.10 lb per mmBTU of heat input. For example:

Uncontrolled = 1.75 lb PM per mmBTU, Section 1.1 of AP-42

W/Existing ESP = (1.75 lb PM per mmBTU) (1 – 0.945) ≈ 0.10 lb PM per mmBTU

"Present Day BACT" W/ESP = (1.75 lb PM per mmBTU) (1 – 0.945) (1 – 0.845) ≈ 0.015 lb PM per mmBTU

c. TEC provided information suggesting that the control of sulfuric acid mist with a lime sprayer is unclear at low uncontrolled emission levels and probably no greater 35%. The Department notes that BACT for gas turbine projects is typically determined to be the firing of low sulfur fuels.

According to this revised netting analysis, the Bayside re-powering project requires BACT determinations for emissions of CO, PM/PM_{10}, and VOC. Based on discussions with the Department, TEC submitted a revised netting analysis similar to the Department's except as noted for CO emissions.

4. DRAFT BACT AND EMISSIONS STANDARDS

4.1 Available Information

In addition to the information submitted by the applicant, the Department also relied on the following information to make these determinations:

- EPA Region 4 provided comments on 12/15/00 during application processing;
- Hillsborough EPC provided written comments on 10/19/00 and 11/15/00 and verbal comments on 12/13/00;
- DOE web site information on Advanced Turbine Systems Project;
- General Electric technical documents regarding DLN emissions and the gas turbine control system;

- Equipment cost quotes for a CO oxidation catalyst system;
- Equipment cost quotes provided for SCR and SCONOx™ systems;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- AP-42, Section 1.1 for coal-fired boilers (09/98);
- AP-42, Section 3.1 for gas turbines (04/00);
- Annual Operating Reports for the Gannon Plant;
- Recently issued Department permits for the General Electric Model PG7241(FA) gas turbine;
- Goal Line Environmental Technology Website: http://www.glet.com; and

The Department also reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse. A list of recent determinations regarding similar projects in the United States is provided in Table 4.1 on the following page.

4.2 Authorized Fuels

The DEP/TEC Consent Final Judgment requires re-powering the Gannon Units with natural gas. However, this settlement agreement neither allows nor prohibits backup fuels. The EPA/TEC Consent Decree also requires re-powering with natural gas, but does allow the firing of low sulfur No. 2 distillate fuel oil in the combined cycle units, provided: the unit cannot be fired with natural gas; the unit has not yet been fired with No. 2 fuel oil as a backup fuel for more than 875 full load equivalent hours in the calendar year in which TEC wishes to fire the unit with such oil; the oil to be used in firing the unit has a sulfur content of less than 0.05% sulfur by weight; TEC uses all emission control equipment for that unit when it is fired with such oil to the maximum extent possible; and TEC complies with all applicable permit conditions, including emissions rates for firing No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

The Department recognizes the need for such flexibility for a base-loaded plant and will also establish emissions standards for oil firing. Therefore, the Draft Permit will include the following equivalent fuel specifications and restrictions as applicable permit conditions.

➤ The primary fuel for each combined cycle gas turbine shall be pipeline-quality natural gas containing no more than 2 grains of sulfur per 100 SCF of natural gas.

➤ Each unit may be fired with No. 2 distillate oil (or a superior grade) as a backup fuel, providing: the unit cannot fire natural gas; the unit shall fire no more than 11,775,000 gallons of distillate oil during any consecutive 12 months (equivalent to 875 hours per year of full load oil firing); the distillate oil contains less than 0.05% sulfur by weight; all air pollution control equipment (water injection and SCR systems) are functional and used to the maximum extent possible; and the unit is in compliance with the emissions standards of this permit.

4.3 Draft CO and VOC BACT Standards

Discussion

Gas turbines emit carbon monoxide (CO) and volatile organic compounds (VOC) due to incomplete combustion of the fuels. For many combustion processes, CO emissions are inversely proportional to NOx emissions. However, the dry low-NOx combustor design for General Electric's large frame gas turbines has also successfully reduced CO emissions concurrently with NOx emissions. Because the controls or techniques used to lower CO emissions would also lower VOC emissions, the control technologies for these pollutants are reviewed together.

Requested Emissions Standards

The applicant identified two control options that are technically feasible and commercially available for gas turbines: efficient combustion design with good operating practices and an oxidation catalyst. After attaining a lean premix steady-state operation, the dry low-NOx combustion design of the General Electric

Table 4.1 - Brief Summary of Emissions Standards for 170 MW Combined Cycle Gas Turbine Projects

Project Location	Date	CT Model	Unit MW	Control Technologies	CO Limit ppmvd @ 15% O2	NOx Limit ppmvd @ 15% O2	PM Limit	SAM Limit	VOC Limit ppm
Calpine Sutter, CA (LAER)	11/99	S/W 501FD	170	DLN/SCR/OC	4, gas	2.5, gas	11.5 lb/hr	NI	NI
Tenaska Gen., AL (AL-0132)	11/99	GE 7FA	170	DLN/WI/SCR	20, gas 28, oil	3.5, gas 12, oil	NI	NI	7, gas 12, oil
KUA Cane Island Unit 3, FL	11/99	GE 7FA	170	DLN/SCR	10, gas 30, oil	3.5, gas w/DB	10% opacity Good Combustion	LSF	1.4, gas 10, oil
Lake Worth Generation, FL	11/99	GE 7FA	170	DLN/WI Optional SCR/OC	3.5/9, gas 5.9/20, oil	9/3.5, gas 42/16.4, oil	10% opacity Good Combustion	LSF	1.4, gas 3.5, oil
Hinds Energy, MS (MS-0037)	01/00	GE 7FA?	170	DLN/SCR	20, gas	3.5, gas	NI	NI	NI
Attala Energy, MS MS-0039	02/00	GE 7FA?	170	DLN/SCR	20, gas	3.5, gas	NI	NI	NI
Calpine Delta, CA (LAER)	02/00	GE 7FA or S/W 501FD	170	DLN/SCR	10, gas w/DB (3-hr CEMS avg.)	2.5, gas w/DB	0.25 gr. S/100 SCF of natural gas	NI	2, gas
Calpine Bullhead City,	02/00?	S/W 501FD	170	DLN/SCR	10, gas w/DB (3-hr CEMS avg.)	3.0, gas w/DB	18.3 lb/hr 22.8 lb/hr w/DB, PA	NI	1.5, gas
Mobile Energy, AL (AL-0143)	03/00	GE 7FA	170	DLN/WI/SCR	18, gas w/DB 26, oil w/DB	3.5, gas w/DB 11, oil w/DB	10% opacity Good Combustion	NI	5, gas 6, oil
GPC Boat Rock, AL (AL-0141)	04/00	GE 7FA	170	DLN/SCR	30, gas w/DB	3.5, gas w/DB	NI	NI	8, gas w/DB
Calpine Osprey, FL	05/00	S/W 501FD	170	DLN/SCR	10, gas (24-hr CEMS avg.)	4.0, gas w/DB	10% opacity 24.1 lb/hr w/DB	LSF	2.3, gas 4.6, gas w/DB, PA
CPV Gulfcoast	11/00	GE 7FA	170-	DLN/WI/SCR	9, gas 20, oil	3.5, gas 10, oil	10% opacity 20 lb/hr, gas 53 lb/hr, oil	LSF	1.4, gas 3.6, oil
Hines PB II, FL	01/01	S/W 501FD	170	DLN/SCR	16, gas 30, oil	3.5, gas 12, oil	7.3, gas 64.8, oil	LSF	2, gas 10, oil
TEC Bayside, FL	*Draft*	**GE 7FA**	**170**	**DLN/SCR/WI**	**8, gas 20, oil**	**3.5, gas 12, oil**	**10% opacity 12 lb/hr, gas 36 lb/hr, oil**	**LSF**	**1.3, gas 3, oil**

Abbreviations:

Manufacturer	Controls	Other
GE – General Electric	DLN – Dry Low-NOx	LAER – Lowest Achievable Emission Rate
S/W – Siemens/Westinghouse	SCR - Selective Catalytic Reduction	BACT – Best Available Control Technology
	WI = Water or Steam Injection	CEMS – Continuous Emissions Monitoring System

Notes: All data presented is for combined cycle gas turbine projects with a nominal direct electrical generating capacity of approximately 170 MW. Many of the limits presented are estimates based on assumptions made to present consistent units for comparison. "NI" means no information was available. "LSF" means low sulfur fuels specified.

Model PG7241(FA) gas turbine results in low emissions of CO and VOC while also maintaining low NOx emissions. The Speedtronic™ automated gas turbine control system monitors and controls the gas turbine combustion process and operating parameters including, but not limited to, air/fuel distribution and staging, turbine speed, load conditions, temperatures, heat input, and fully automated startup/shutdown. The dry low-NOx combustion design and Speedtronic™ control system are integral to the Model PG7241(FA) gas turbine. "Good operating practices" means operating the unit in accordance with the manufacture's recommendations for efficient combustion, properly maintaining the gas turbine, and appropriate tuning of the combustors and controls system. No adverse energy, environmental, or economic impacts were identified for the use of an efficient combustion design and good operating practices.

An oxidation catalyst consists of a noble metal catalyst section incorporated into the gas turbine exhaust. The catalyst promotes greater oxidation of CO (to carbon dioxide) and VOC (to carbon dioxide and water) at much lower temperatures (650°F to 1150°F) than would occur without a catalyst. Control efficiencies are primarily a function of the gas residence time, catalyst activity, and uncontrolled emission levels. CO control efficiencies can approach 90%. VOC control efficiencies would likely be in the 30% to 50% range due to the low uncontrolled VOC emissions from the Model PG7241(FA) gas turbine, which should be less than 3.0 ppmvd corrected to 15% oxygen.

The applicant recognized an oxidation catalyst combined with the efficient combustion of the Model PG7241(FA) gas turbine as the top control for CO and VOC emissions, but identified the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst results in a pressure drop across the catalyst bed of approximately 1 inch of water column. This pressure drop causes backpressure on the gas turbine and reduces the power output from the unit. The applicant estimates the lost power generation to be $671,822 per year for all seven gas turbines combined.

Environmental Impacts: Although the project proposes natural gas and very low sulfur distillate oil as the only fuels, the oxidation catalyst would oxidize small amounts of fuel sulfur to sulfuric acid mist. Also, due to the inherently low VOC emissions from the Model PG7241(FA) gas turbine, the applicant believes that the addition of an oxidation catalyst would result in negligible ambient air quality impacts. The Bayside project is located in Hillsborough County, an area that is in attainment (or designated as "maintenance" or "unclassifiable") for all criteria pollutants.

Economic Impacts: The applicant estimates that the installation of an oxidation catalyst would result in total capital investment of between $8,716,033 and $9,586,600 for all seven gas turbines combined. The total annualized costs for the oxidation catalyst systems were estimated to be about $2.4 and $2.6 million per year. Assuming 50% control efficiency for VOC emissions, the applicant estimates that the oxidation catalyst system would remove an additional 50 tons of VOC per year. The cost effectiveness would be approximately $48,000 to $52,000 per ton of VOC removed for the oxidation catalyst system. Assuming 90% control efficiency for CO emissions, the applicant estimates that the oxidation catalyst system would remove an additional 891 tons of CO per year. The cost effectiveness would be approximately $2700 to $2900 per ton of CO removed for the oxidation catalyst system.

The applicant rejected the oxidation catalyst system as not cost effective for the Bayside re-powering project as well as not producing any measurable reductions in air quality impacts. The applicant proposed the following CO and VOC emissions standards for each gas turbine based on the efficient combustion design of the Model PG7241(FA) and good operating practices.

- Requested CO Standard: 7.8/30.3 ppmvd corrected to 15% oxygen for gas/oil firing
- Requested VOC Standard: 1.3/3.0 ppmvd corrected to 15% oxygen for gas/oil firing

Draft BACT Determinations

The Department also recognizes an oxidation catalyst system combined with the efficient combustion of the

Model PG7241(FA) gas turbine as the top control for CO and VOC emissions. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

Energy Impacts: The Department agrees that installation of an oxidation catalyst would result in an energy penalty due to the pressure drop across the catalyst.

Environmental Impacts: Although the oxidation catalysts systems could result in increased sulfuric acid mist emissions, the oxidation process would also result in lower sulfur dioxide emissions. However, the Department believes that such increases and decreases would be minimal due to the very low sulfur contents of the proposed fuels. The Department rejects the applicant's argument that the further reduction of CO and VOC emissions would have negligible ambient impacts. The PSD preconstruction review process was specifically established for areas that were meeting the state ambient air quality standards in order to prevent the deterioration of the current air quality. Ambient impacts are evaluated in the modeling analysis and are not considered in making a determination of the Best Available Control Technology. The Department also notes that an oxidation catalyst would reduce emissions of hazardous air pollutants, such as formaldehyde.

Economic Impacts: The applicant's estimate of the cost effectiveness for an oxidation catalyst system is reasonable when compared to other projects.

Due to the high temperatures and efficient combustion, VOC emissions are already guaranteed at very low rates. Based on recent emissions performance tests for this model, actual CO emissions are expected to be much lower than General Electric's guaranteed emission rates. TEC's Polk Power Station recently tested a General Electric Model PG7241(FA) gas turbine while firing each fuel. The test results indicate CO emission levels of less than 1/2 ppmvd when firing gas/oil. Such low actual CO emissions would drive the cost effectiveness of an oxidation catalyst system even higher.

The Department believes that installation of an oxidation catalyst would not be cost effective given the low emissions characteristics of this particular gas turbine. Therefore, the Department rejects an oxidation catalyst as not cost effective for this project and determines that the efficient combustion design of this model and good operating practices to be the Best Available Control Technology. The following standards are established as the draft BACT standards for performance testing conducted at base load:

- CO Draft BACT: 7.8/15.0 ppmvd corrected to 15% oxygen for gas/oil firing

In addition the Department establishes the following continuous CO emissions standard as draft BACT standards for CO and as surrogate standards for VOC:

- CO Draft BACT: 9.0/20.0 ppmvd corrected to 15% oxygen for gas/oil firing (24-hour block avg.)

Because VOC emissions are expected to be within the minimum detectable levels of the test methods, the continuous CO standards shall also serve as surrogate BACT standards for emissions of VOC. The Department believes the applicant's request for a CO emissions standard of 30.3 ppmvd corrected to 15% oxygen for oil firing is not justified by actual field test data. This level of emissions was based on a relatively high ambient temperature and operation at 50% base load. This set of conditions is not likely to occur for prolonged periods considering this is a base-loaded plant with evaporative cooling. In addition, the Department has emissions performance curves from the manufacturer that do not identify these higher emissions. The Department believes the slightly higher continuous emissions limits provide adequate flexibility for demonstrating compliance with a 24-hour block CEMS average.

4.4 Draft PM/PM$_{10}$ BACT Standards

Discussion

Emissions of particulate matter will result from the combustion of natural gas and low sulfur distillate oil. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. However, natural gas and very low sulfur distillate oil are clean fuels containing little ash, sulfur, or other contaminants.

Requested Emissions Standards

At the estimated uncontrolled emission rates when firing pipeline-quality natural gas and very low sulfur distillate oil, the applicant believes the installation of add-on controls such as baghouses or electrostatic precipitators would be cost prohibitive. In addition to the specifications and restrictions for authorized fuels, the applicant proposed the following visible emissions limit as a work practice standard in lieu of a particulate matter emissions standards.

- Visible emissions shall not exceed 10% opacity (6-minute average) when firing either fuel.

Draft BACT Determinations

The Department agrees that further control of particulate matter emissions with add-on controls would be cost prohibitive due to the low uncontrolled emissions rates. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration for this project. Therefore, to the specifications and restrictions for authorized fuels, the following conditions are established as the draft BACT standards for particulate matter.

- The primary fuel for each combined cycle gas turbine shall be pipeline-quality natural gas containing no more than 2 grains of sulfur per 100 SCF of natural gas.
- The backup fuel shall be No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight and subject to the restrictions listed under "authorized fuels".
- Visible emissions shall not exceed 10% opacity (6-minute average) when firing gas or oil.

The continuous CO standards shall serve as surrogate BACT standards for emissions of particulate matter.

4.5 Draft NOx Standards

Zero Ammonia Technology Issue

Due to the emissions decreases resulting from the shutdown of the existing coal-fired Gannon Units 5 and 6, a BACT determination was not required for emissions of nitrogen oxides. However, the DEP/TEC Consent Final Judgment requires installation of selective catalytic reduction (SCR) systems on each combined cycle unit. SCR is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850° F, which is within the range of the exhaust from the heat recovery steam generators. SCR is a commercially available, demonstrated control technology currently employed on numerous combined cycle combustion turbine projects and is capable of very low NOx emissions with control efficiencies approaching 90%, depending primarily on the uncontrolled NOx emission rate.

The DEP/TEC Consent Final Judgment also requires an evaluation of a "Zero Ammonia Technology" control system for at least one of the combined cycle gas turbine units. SCONOx™ is a zero ammonia technology for the control of CO and NOx emissions developed by Goal Line Environmental Technologies and distributed by Alstom Power for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which is within the operating range of the exhaust gas from heat recovery steam generators. SCONOx™ can achieve control efficiencies in the range of 90% to 98%. If the differential installed cost between SCONOx™ and SCR is less than $8 million, TEC must install a SCONOx™ system on at least one of the Bayside combined cycle gas turbine units.

The Department worked closely with TEC on developing appropriate cost estimates in accordance with the Consent Final Judgement. The cost differential between the two control technologies was determined to be greater than $8 million. Therefore, TEC is not required to install a SCONOx™ system. SCR systems shall be installed on all seven combined cycle units at the Bayside Power Station and designed to minimize ammonia emissions.

NOx Controls and Standards

For the Bayside project, an SCR system will be installed on each combined cycle unit in combination with the dry low-NOx combustion design when firing the primary fuel of natural gas and water injection when firing distillate oil as a backup fuel. At the time of this project, this level of control is generally accepted as BACT for attainment areas. The applicant requests the following NOx emissions standards.

➤ NOx Standard: 3.5/16.4 ppmvd corrected to 15% oxygen for gas/oil firing

The DEP/TEC Consent Final Judgment requires the installation of SCR for each combined cycle unit with a NOx emission standard of 3.5 ppmvd corrected to 15% oxygen when firing natural gas. However, it is silent on the issue of firing distillate oil as a backup fuel as well as ammonia emissions resulting from SCR. As discussed previously, EPA/TEC Consent Decree conditionally allows the firing of low sulfur distillate oil provided that all air pollution control equipment is utilized to the "maximum extent possible".

For two recent similar projects (Tenaska Alabama II Partners, L.P. and Hines Power Block No. 2), BACT for NOx emissions was determined to be 3.5/12.0 ppmvd corrected to 15% oxygen for gas/oil firing. These projects were based on the installation of an SCR system for combined cycle gas turbines of a similar size. The Hines Power Block No. 2 project also established an ammonia slip rate of 5/9 ppmvd corrected to 15% oxygen for gas/oil firing. The Department accepts 12.0 ppmvd corrected to 15% oxygen with an ammonia slip of 9 ppmvd corrected to 15% oxygen as utilization of the SCR system to the "maximum extent possible" when firing distillate oil as a backup fuel. Therefore, the Department establishes the following draft NOx emissions standards.

➤ NOx Standard: 3.5/12.0 ppmvd corrected to 15% oxygen for gas/oil firing (24-hour block avg.)

These limits are much more stringent than the NOx standards of NSPS, Subpart GG.

4.5 Draft SAM/SO_2 Standards

Due to the emissions decreases resulting from the shutdown of the existing coal-fired Gannon Units 5 and 6, a BACT determination was not required for emissions of sulfur dioxide. However, the state and federal settlement agreements require re-powering with natural gas as the primary fuel. The EPA/TEC Consent Decree allows firing low sulfur distillate oil as a backup fuel. Emissions of sulfur dioxide are generated from sulfur in natural gas and distillate oil when these fuels are combusted. Small amounts of SO_2 may be converted to sulfuric acid mist emissions. Natural gas and very low sulfur distillate oil are clean fuels containing little ash, sulfur, or other contaminants. At the uncontrolled emission rates estimated when firing pipeline-quality natural gas and very low sulfur distillate oil, the installation of add-on controls such as flue gas desulfurization equipment would be cost prohibitive. The applicant requests the specifications and restrictions of the authorized fuels as acceptable work practice standards in lieu of emissions standards.

The Department agrees that further control of sulfur dioxide and sulfuric acid mist emissions with add-on control technologies would be cost prohibitive due to the relatively low uncontrolled emissions of this pollutant. The specification of clean fuels (pipeline-quality natural gas and very low sulfur distillate oil) constitutes a pollution prevention technique and is given favorable consideration for this project. These specifications have previously been established as the draft PM/PM_{10} BACT standards for this project. The fuel sulfur contents proposed are clearly more stringent than the NSPS standard of 0.8% sulfur by weight. The above fuel specifications effectively limit the potential emissions of these pollutants and are typically considered BACT for gas turbine projects Therefore, the

➤ The primary fuel for each combined cycle gas turbine shall be pipeline-quality natural gas containing no more than 2 grains of sulfur per 100 SCF of natural gas.

➤ The backup fuel shall be No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight and subject to the restrictions listed under "authorized fuels".

4.6 Ammonia Emissions

Ammonia is injected into the exhaust gas stream as part of the Selective Catalytic Reduction system that is used to control NOx emissions. Some of the ammonia will escape past the catalyst without reaction, which is known as "ammonia slip". Ammonia emissions can be exhausted as ammonia or combine with sulfur to form fine particulate matter such as ammonium sulfates and bisulfates. Ammonia has been designated as an Extremely Hazardous Substance under federal SARA Title III regulations. It also adds to the nitrogen loading of the waters and soils. As part of the NOx control system, higher levels of ammonia slip can indicate reduced catalyst effectiveness. Limiting ammonia emissions also minimizes the formation of fine particulate matter. Therefore, the Department establishes the following standards for ammonia slip.

➢ Ammonia Slip: 5/9 ppmvd corrected to 15% oxygen for gas/oil firing

4.7 VOC Emissions from the Fuel Oil Storage Tanks: Prior to submittal of the Bayside re-powering application, the applicant requested approval to construct a 5.85 million gallon oil storage tank. The oil storage tank is subject to NSPS Subpart Kb and currently serves the existing Gannon plant. In the future, the tank will serve as backup fuel storage for the Bayside Station combined cycle gas turbines. The Department approved construction and operation of the tank contingent on considering any potential VOC emissions from the tank in the Bayside re-powering application. The Bayside re-powering project already requires a BACT determination for VOC emissions from the gas turbines. The distillate oil tank is subject only to the NSPS Subpart Kb record keeping requirements.

4.8 Excess Emissions: Based on Rules 62-210.700 and 62-4.130, F.A.C. and the design of the gas turbines and control systems, the following conditions will be included in the permit to address periods of excess emissions.

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 calculation of the 24-hour block averages to demonstrate compliance with the continuous CO and NOx emissions standards. [Rule 62-210.700(4), F.A.C.]

Excess Emissions Defined: During startup, shutdown, and unavoidable malfunction, the following permit conditions allow excess emissions or the exclusion of monitoring data. The conditions only apply if operators employ best operational practices to minimize the amount and duration of excess emissions.

- During startup and shutdown, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during any calendar day, which shall not exceed 20% opacity. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.
- Except for startup and shutdown, operation below 50% base load is prohibited.
- A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more and the first stage turbine metal temperature is 250° F or less. To minimize emissions during such startup, no more than one gas turbine shall be operated during a steam turbine cold startup for each Bayside Unit.
- For each Bayside Unit, the permittee shall provide a Startup and Shutdown Plan as part of the application for a Title V air operation permit. The plan shall identify startup and shutdown procedures, duration of the procedures, and the methods used to minimize emissions during these periods. Within 90 days of completing the eighth steam turbine cold startup of a Bayside Unit, the permittee shall submit a revised plan to the Department based on actual operating data and experience. The Department shall review the actual operational data and determine whether the period of data exclusion for a steam turbine cold startup defined under the CEMS requirements shall be *decreased* to represent good operational practices.

CEMS Data Exclusion: The Draft Permit does not allow periods of emissions in excess of the CO and NOx standards, but does allow for the exclusion of specific CO and NOx CEMS data.

- Periods of data excluded for gas turbine startup (excluding steam turbine cold startup), shutdown, or documented unavoidable malfunction shall not exceed two hours in any 24-hour block period . Periods of data excluded for such episodes shall not exceed a total of four hours in any 24-hour block period.
- Periods of data excluded for a steam turbine cold startup shall not exceed sixteen hours in any block 24-hour block period. A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more and the first stage turbine metal temperature is 250° F or less. Based on actual operating experience and data, the Department may *decrease* this period of data exclusion in the Title V air operating permit without modifying this PSD permit. {Note: TEC states their design engineers believe that 16 hours may be necessary to warm up nearly 2000 feet of steam piping and to gradually bring the existing steam turbine up to temperature to prevent thermal fatigue of the materials. The Department has no information available to refute this claim. It is noted that the recent FPL Ft. Myers re-powering project allowed up to 12 hours of data exclusion for a steam turbine cold startup.}
- If the permittee provides at least five days advance notice prior to a tuning session, data may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards. Periods of data excluded for such episodes shall not exceed a total of three hours in any 24-hour block period.

5. MACT 112(g) APPLICABILITY

The application states that potential formaldehyde emissions are 7.25 tons per year and total HAP emissions are 27.87 tons per year. Total HAP emissions are above the threshold of 25 tons per year, which requires a case-by-case MACT determination in accordance with Section 112(g). Because Bayside Units 1 and 2 are attached to individual stream turbines, TEC believes that Section 112(g) allows evaluation as separate "process units". Based on this interpretation, neither unit would trigger the MACT thresholds. The Department believes that TEC's interpretation is flawed because projects could be contrived simply to avoid MACT applicability regardless of the actual HAP emissions.

The Department believes that the HAP emissions from all of the Bayside gas turbines must be aggregated for comparison to the HAP major source thresholds. Jim Little of EPA Region 4 confirmed the Department's interpretation with Sims Roy, the author of EPA's interpretative rule for MACT determinations regarding gas turbines. In addition, Mr. Little confirmed the Department's interpretation with Kathy Kaufman, the EPA 112(g) MACT coordinator. TEC's interpretation is not in accordance with MACT program as interpreted by the Department and EPA. Absent a proposed MACT determination from TEC, the Department reviewed the following available information.

- EPA may propose MACT to be an oxidation catalyst for new gas turbine projects (2001).
- Formaldehyde emissions are the single greatest HAP emission. The highest levels of formaldehyde emissions occur when firing natural gas.
- The application estimates formaldehyde emissions to be 7.25 tons per year and total HAP emissions to be 27.87 tons per year. The total "organic" HAP emissions constitute approximately 22 tons per year of HAP emissions. An oxidation catalyst would only control organic HAP emissions.
- EPA updated Section 3.1 of AP-42 in April of 2000 to include emission factors for HAP emissions. TEC selected only the HAP emission rates for gas turbines larger than 100 MW for use in this project. This seems appropriate because many of the remaining test results were for smaller units (< 30 MW), which typically have lower exhaust temperatures and combustion efficiencies (CO emissions of 25 ppmvd or higher). The HAP emission rates used for the larger gas turbines were based on tests for older model units.
- The General Electric Model PG7241(FA) has an exhaust temperature of 1100° F to 1200° F. The maximum CO and VOC emissions when firing natural gas are approximately 8 and 2 ppmvd corrected to 15% oxygen.

respectively. Recent test reports for this model gas turbine indicate actual CO emissions are less than 1 ppmvd when firing natural gas. General Electric has not yet released HAP emissions data specific to the Model PG7241(FA) gas turbine.

- The Bayside combined cycle units include the necessary equipment that would simplify after-the-fact installation of an oxidation catalyst, should it later be required.

Because estimated potential emissions are just above the major source HAP thresholds and there is little HAP emissions data available for this specific model, the Department defers 112(g) MACT applicability at this time. Therefore, the Department will specify the following testing requirements to resolve this issue:

1. TEC will test at least one installed Bayside Unit 1 combined cycle gas turbine for emissions of acetaldehyde, formaldehyde, toluene, and xylene as determined by EPA Method 18.
2. The tests will be conducted between 65-75% and 90-100% base load. For each load condition, the tests shall consist of at least three 1-hour runs.
3. Emissions will be reported in terms of ppmvd @ 15% oxygen, lb/mmBTU, lb/MW-hr, and lb/hr.
4. The test report shall include a revised MACT applicability analysis and propose a MACT, if necessary.

The Department will review the test results and determine whether or not the Bayside project triggers a MACT determination. If so, the Department will modify the PSD permit to include MACT controls.

6. SUMMARY OF EMISSIONS STANDARDS AND COMPLIANCE METHODS

Table 6.1 Summary of Emissions Standards

Pollutant	Gas Firing	Oil Firing
Standards Based on Emissions Performance Tests (Based on permitted capacity and an inlet temperature of 59° F)		
Ammonia	5 ppmvd @ 15% O_2	9 ppmvd @ 15% O_2
CO (BACT)	7.8 ppmvd @ 15% O_2 28.7 lb/hr	15.0 ppmvd @ 15% O_2 64.5 lb/hr @ 59° F
Fuel Specification (BACT)	Natural Gas: 2 grains sulfur per 100 SCF	Distillate Oil: 0.05% sulfur by weight
NOx	3.5 ppmvd @ 15% O_2 23.1 lb/hr	12.0 ppmvd @ 15% O_2 79.2 lb/hr @ 59° F
PM/PM_{10} (BACT)	Fuel Specifications 10% Opacity, 6-minute average CO standard is a surrogate. {12 lb/hr, estimated maximum}	Fuel Specifications 10% Opacity, 6-minute average CO standard is a surrogate. {30 lb/hr, estimated maximum}
SAM/SO_2	Fuel Specifications	Fuel Specifications Oil use limited to equivalent of 875 hr/yr.
VOC (BACT)	Efficient combustion and operating practices CO standard is a surrogate. {Estimated maximum is 3.0 lb/hr, equivalent to 1.3 ppmvd @ 15% O_2.}	Efficient combustion and operating practices CO standard is a surrogate. {Estimated maximum is 7.5 lb/hr, equivalent to 3.0 ppmvd @ 15% O_2.}
Standards Based on CEMS Data		
CO (BACT)	9.0 ppmvd @ 15% O_2, 24-hr block avg.	20.0 ppmvd @ 15% O_2, 24-hr block avg.
NOx	3.5 ppmvd @ 15% O_2, 24-hr block avg.	12.0 ppmvd @ 15% O_2, 24-hr block avg.

Notes:

a. Compliance shall be determined based on a 3-run test average conducted between 90% and 100% of the permitted capacity.

b. Measured mass emission rates (pounds per hour) shall be corrected to a compressor inlet temperature of 59° F based on General Electric emissions performance curves or equations specific to the Model PG7241(FA).

c. NOx emissions are defined as oxides of nitrogen measured as NO_2.

d. The 24-hour block CEMS average is the average emissions for the number of valid operating hours during a 24-hour period. "Valid" operating hours do not include hours that had no operation or hours that were excluded in accordance with the permit conditions regarding startups, shutdowns, and documented unavoidable malfunctions.

Table 6.2 Compliance Methods

EPA 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 • For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run. • For oil firing, the minimum sampling time shall be one hour per run and the minimum sampling volume shall be 30 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 be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography • EPA Method 18 may be used concurrently with EPA Method 25A to deduct non-regulated emissions of methane and ethane from the measured VOC emissions.
20	Determination of Oxides of Nitrogen, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Notes:

a. Initial performance tests shall be conducted for emissions of ammonia, CO, NOx, and opacity when firing each fuel. Thereafter, compliance with the CO and NOx emissions standards shall be determined by valid, certified continuous monitoring data. Compliance with the CO standards shall serve as a surrogate for emissions of PM and VOC.

b. For one unit (Bayside Unit 1A, 1B, or 1C), initial performance tests shall be conducted for emissions of total volatile organic compounds and acetaldehyde, formaldehyde, toluene, and xylene. The test shall be performed at 75% and 100% of base load. For each load condition, the tests shall consist of at least three 1-hour runs.

c. To determine regulated VOC emissions, EPA Method 18 may be conducted concurrently with EPA Method 25A to deduct non-regulated emissions of methane and ethane.

d. The NSPS requirements for testing NOx emissions (EPA Method 20) may be satisfied with EPA Method 7E and valid, certified continuous monitoring data.

e. EPA Method 20 for SO_2 emissions is not required. Compliance shall be demonstrated in accordance with the specified fuel sulfur sampling and analysis as well as the acid rain requirements.

f. A unit firing more than 200 hours of oil per year shall be tested when firing oil for visible emissions and ammonia slip.

g. Annual performance tests shall be conducted each federal fiscal year (October 1st to September 30th) for ammonia and visible emissions when firing gas and when firing oil. Compliance with the CO and NOx emissions standards shall be determined from data collected by the CEM systems during the required annual RATA. Compliance with the CO standards shall serve as a surrogate for emissions of PM and VOC.

7. OTHER PROJECT CONSIDERATIONS

7.1 Shutdown of Gannon Units

The DEP/TEC Consent Final Judgment indicates that Gannon Units 2, 4, and 5 shall be re-powered and Gannon Units 1, 3, and 6 shall be shutdown. The EPA/TEC Consent Decree requires the re-powering of a combination of units totaling at least 550 MW. The Bayside application requests the re-powering of Gannon Units 5 and 6. Correspondence between the Department and TEC (April 19, 20, and 26, 2000) indicates that re-powering Gannon Units 5 and 6 meets the intent of the DEP/TEC Consent Final Judgment.

The applicant used emissions decreases generated from the shutdown of existing Gannon Units 5 and 6 to "net out" of PSD applicability for several pollutants. Therefore, the Draft Permit will require the applicable Gannon Unit to be shut down prior to commencing operation of each corresponding Bayside Unit. This will not impose any hardship on TEC because the existing Gannon Units must be disconnected from the steam-electrical turbines during construction. The Draft Permit will also require the shutdown of the remaining Gannon Units 1-4 before January 1, 2005.

7.2 Interim Coal Firing

The applicant did not predict any emissions increases for existing coal-fired Gannon Units 1-4 after the shut down of Gannon Units 5 or 6. To ensure that large increases in actual emissions do not occur from these units, the Draft Permit will reduce the limit on the total heat input through the coal yard when Gannon Units 5 and 6 are shut down. Based on the representative 2-year "past actual" average coal firing rates for each unit and the average coal heat content, the reduced heat inputs are:

Table 7.2, Coal Yard Heat Input Limits

Unit	Tons Coal per Year	BTU per lb coal	mmBTU per year
Title V Permit Limit. All Gannon Units			$69.9 \times 10^{+06}$
Gannon Unit 5	549,023	12,000	$13.2 \times 10^{+06}$
Gannon Units 1, 2, 3, 4 and 6; Remaining After Shutdown of Unit 5			$56.7 \times 10^{+06}$
Gannon Unit 6	890,562	12,000	$21.4 \times 10^{+06}$
Gannon Units 1, 2, 3, and 4; Remaining After Shutdown of Units 5 and 6			$35.3 \times 10^{+06}$
Gannon Units 1-6. After 12/31/2004			0

Therefore, when Gannon Unit 5 is shutdown, the coal yard heat input will be reduced from 69.9 to 56.7 x 10^{+06} mmBTU per year. When Gannon Unit 6 is shutdown, the coal yard heat input will be reduced from 56.7 to 35.3 x 10^{-06} mmBTU per year. In accordance with the EPA/TEC Consent Decree, all six coal-fired boilers must be shutdown and cease operation before January 1, 2005. Shutdown means the permanent disabling of a coal-fired boiler such that it cannot burn any fuel (including "wood-derived" fuels) nor produce any steam for electricity production, other than through re-powering. The Draft Permit will require the dispatch of any operational Bayside Unit before operating any existing Gannon Unit.

7.3 Re-Powering Other Units

The EPA/TEC Consent Decree requires TEC to shutdown and cease any and all operation of all six Gannon coal-fired boilers before January 1, 2005. It allows TEC to retain any shutdown unit on reserve/standby, unless such unit is to be (or has been) re-powered. If TEC later decides to restart any shutdown unit retained on reserve/standby, then TEC must timely apply for a PSD permit for the unit to be re-powered and abide by such permit (including installation of BACT and its corresponding emission rate as determined at the time of the restart). TEC must operate the re-powered unit to meet the NOx emission rate established in the PSD permit or an emission rate for NOx of 3.5 ppmvd corrected to 15% oxygen, whichever is more stringent. TEC must provide a copy of any permit applications, proposed permits, and permits to the EPA. For any unit shutdown and placed on reserve/standby, TEC also may elect to fuel such a unit with a gaseous fuel other than (or in addition to) natural gas, if and only if TEC: applies for and obtains 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.

Both the state and federal settlement agreements require the shutdown of Gannon Units 1-4 before January 1, 2005. The shutdowns may potentially result in emissions decreases. However, the emissions decreases must be based on actual emissions during the two years immediately preceding any proposed future project. Because the settlement agreements require the shutdowns and re-powering the Gannon plant with natural gas, "normal operations" for Gannon Units 1-4 are expected to be greatly reduced in 2003 with little or no operation in 2004.

7.4 Permanent Bar on Combustion of Coal

The EPA/TEC Consent Decree prohibits TEC from combusting coal in the operation of any unit at Gannon plant commencing on January 1, 2005.

8. AIR QUALITY IMPACTS

8.1 Executive Summary

In accordance with Rule 62-212.400(5)(d), F.A.C., an ambient impact analysis is required for projects subject to the PSD preconstruction review requirements. For each emission increase exceeding a PSD significant emissions rate defined in Table 62-212.400-2, F.A.C., the applicant must demonstrate that the project will not cause or contribute to a violation of any ambient air quality standard or maximum allowable ambient increase. Nitrogen dioxide (NO_2), particulate matter (PM_{10}), and sulfur dioxide (SO_2) are criteria pollutants with defined ambient air quality standards (AAQS), PSD increments, Class I significant impact levels, and Class II significant impact levels. Carbon monoxide (CO) is a criteria pollutant with defined AAQS and PSD Class II significant impact levels. VOC is a precursor to the criteria pollutant ozone with a defined threshold of 100 tons per year, above which could trigger an ambient impact analysis.

As previously described, the proposed project will increase net emissions of CO and VOC in excess of PSD significant emission rates. Although the evaluation of Best Available Control Technology included PM_{10}, this was based on the revised netting analysis, which assumed "present day" BACT controls were installed on existing Gannon Units 5 and 6. In reality, no such controls are in place and the Bayside project will result in a net emissions decrease for PM_{10} as well as NO_2 and SO_2. Therefore, an evaluation of the ambient impacts from the significant emissions of CO and VOC is required for the Bayside project. In addition, an analysis must be performed for the project impacts on soils, vegetation, and visibility as well as impacts to air quality related to growth resulting from the project.

The net VOC emissions increase from the Bayside project is 71 tons per year (99.6 potential tons per year). This emission rate is greater than the PSD significant emission rate of 40 tons per year, but is less than the de minimis level of 100 tons per year listed in Table 212.400-3, F.A.C. Therefore, no ambient impact analysis was required for VOC emissions. Even if the project did result in a VOC emissions increase above the de minimis level, the Department typically determines that it is not feasible to use regional models that incorporate the complex chemical mechanisms for predicting ozone formation resulting from specific projects.

The applicant's preliminary ambient impact analysis for CO revealed no significant impacts in the PSD Class II areas surrounding the proposed facility. Therefore, a full analysis evaluating the project impacts related to the Class II areas, the AAQS, and the PSD Class II increments was not required. No analysis for the project impacts to Class I areas were required because CO has no defined PSD Class I significant impact levels.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

8.2 Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempt or satisfied. If available, representative existing monitoring data may be used to satisfy this monitoring requirement. For each pollutant, an exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the air quality modeling predicts that the maximum ambient impact resulting from the emissions increase is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentration is less than a pollutant-specific de minimis ambient concentration. If preconstruction ambient monitoring is exempted, a determination of the background concentration for each PSD significant pollutant with an established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling. No de minimis ambient concentration is provided for ozone. Instead the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year. The following table shows the maximum predicted air quality impacts from the project compared to the de minimis levels listed in Table 212.400-3, F.A.C.

8.2 Maximum Air Quality Impacts Compared to the De Minimis Levels

Pollutant	Averaging Time	Maximum Predicted Impact	De Minimis Level	Greater Than De Minimis Impact?
CO	8-hour	163 $\mu g/m^3$	575 $\mu g/m^3$	No
VOC	Annual Emission Rate	71	100 TPY	No

As shown in the table, CO and VOC emissions are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required for these pollutants. Also, because VOC is below the specified de minimis level, no ambient impact analysis is required for VOC emissions.

8.3 Models and Meteorological Data Used in Significant Impact and AAQS Analyses

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. The stack height proposed for each Bayside gas turbine is 150 feet, which is less than the de minimis GEP stack height of 65 meters (213 feet). Therefore, the stacks will not exceed the good engineering practice (GEP) stack height criteria. Direction-specific downwash parameters were used for all sources for which downwash was considered.

Meteorological data used in the ISCST3 model was obtained from the National Climatic Data Center (NCDC) and consisted of the concurrent 5-year period from 1992 through 1996. This NCDC station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. Surface data was from the St. Petersburg/Clearwater International Airport (SPG), Station ID 72211. Upper air data was from Ruskin (RUS), Station 12842. The surface and mixing height data for each of the five years were processed using EPA's PCRAMMET meteorological preprocessing program to generate the meteorological data files in the format required by the ISCST3 dispersion model.

Because five years of data are used in ISCST3, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted annual average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

8.4 Significant Impact Analysis

A PSD Class II significant impact analysis was performed for CO emissions impacts. Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. Over 500 receptors were placed along the facility's restricted property line and out to 12 km from the facility, which is located in a PSD Class II area. Receptors were placed at 10-degree increments beginning at 10 degrees on rings at 250 and 500 meters, if the specific polar receptor was an ambient air location. Complete rings with receptors located at 10-degree increments beginning at 10 degrees were located at 250-meter increments from 750 to 7000 meters and at 8000, 9000, 10,000, and 12,000 meters. These receptor grids are consistent with prior dispersion modeling studies submitted to the Department for this site.

For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, the modeling analysis compares maximum predicted impacts due to the project with PSD significant impact levels. This will reveal whether the project will cause or contribute to significant impacts in the vicinity of the facility (Class II areas) or in a Class I area based on the model's predictions. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required. In addition to the impact from the project, a full impact analysis also considers impacts from other major sources located within the vicinity of the project as well as background concentrations to determine whether the project will cause or contribute to an exceedance of an applicable AAQS or PSD increment. Consequently, a preliminary modeling analysis showing an insignificant impact is accepted as the required air quality analysis and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant.

Because distillate oil firing resulted in the highest emissions rates, twelve scenarios were modeled for oil firing consisting of three load conditions and four compressor inlet temperatures. The following table shows the results of the significant impact analysis.

Table 8.4 Maximum Air Quality Impacts Compared to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact? (Yes/No)
CO	8-hour	163	500	No
	1-hour	411	2,000	No

As shown in the table, no significant CO emissions impacts are predicted in the vicinity of the facility (Class II areas). There are no PSD significant impact levels defined for CO emissions impacts to Class I areas. Therefore, no further modeling analysis was required for this project.

8.5 Requested Modeling Analysis

At the request of the Department, the applicant did perform an ambient impact analysis for CO, NO_2, PM/PM_{10}, and SO_2 based on the ISCST3 air dispersion model and the 12 scenarios for distillate oil, the worst-case fuel. The following table summarizes the results based on the November 17th revision:

Table 8.5 Maximum Predicted Ambient Impacts from Bayside Project

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Florida AAQS ($\mu g/m^3$)	Federal AAQS ($\mu g/m^3$)
CO	HSH, 1-hr	408	40,000	40,000
	HSH, 8-hr	134	10,000	10,000
NO_2	Annual	5	100	100
PM_{10}	HSH, 24-hr	54	150	150
	Annual	4	50	50
SO_2	HSH, 3-hr	320	1300	1300
	HSH, 24-hr	85	260	365
	Annual	5	60	80

The analysis indicates that the project, evaluated independently, will not cause a violation of the state or federal ambient air quality standards.

8.6 Analysis of Additional Impacts on Soils, Vegetation, Visibility, and Air Quality (from Growth)

The Bayside project is the re-powering of an existing coal-fired plant with modern combined cycle gas turbines fired primarily with natural gas. After shutdown of all coal-fired units, it is estimated that the project will reduce actual emissions of nitrogen oxides by more than 28,000 tons per year, particulate matter by more than 1000 tons per year, and sulfur dioxide by more than 60,000 tons per year. The chart presented as Attachment B provides an estimate of the expected actual emissions reductions. The modeling predicted insignificant impacts from increased CO emissions. The maximum ambient impacts from the project alone are predicted to be less than the respective ambient air quality standard (AAQS). Because the AAQS are designed to protect both the public health and welfare, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant. Because the project involves the re-powering of an existing plant, it is believed there will be little growth associated with this project.

9. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the Air Quality Analysis, and the conditions specified in the Draft Permit. Chris Carlson and Cleve Holladay are the project meteorologists responsible for reviewing and validating the Air Quality Analysis for this project. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determination, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at 850/488-0114 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

(DRAFT PERMIT)

PERMITTEE:

Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619

Authorized Representative:
Ms. Karen Sheffield, General Manager

Project No.	0570040-013-AC
Air Permit No.	PSD-FL-301
Facility ID No.	0570040
SIC No.	4911
Expires:	December 31, 2004

PROJECT AND LOCATION

This permit authorizes construction of seven new combined cycle gas turbines to re-power the existing Gannon Station with a nominal electrical production capacity of approximately 1700 MW. The existing plant is renamed the "Bayside Power Station" and is located within the existing plant boundaries on Tampa's Port Sutton Road in Hillsborough County, Florida. The UTM coordinates are Zone 17, 360.00 km E, 3087.50 km N.

STATEMENT OF BASIS

The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department. This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40 CFR 52.21. Specifically, this permit is issued pursuant to the Chapter 62-212, F.A.C. requirements for Preconstruction Review of Stationary Sources and the Prevention of Significant Deterioration (PSD) of Air Quality. The conditions of this permit do not relieve the permittee from any applicable requirement of the DEP/TEC Consent Final Judgement or the EPA/TEC Consent Decree.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A	- Terminology
Appendix B	- Summary of BACT and Emissions Standards
Appendix E	- Summary of Mass Emissions for Given Inlet Temperatures
Appendix GC	- General Conditions
Appendix GG	- NSPS Subpart GG Requirements for Gas Turbines
Appendix XS	- Semi-Annual Continuous Monitor Systems Report

(DRAFT)

Howard L. Rhodes, Director — (Date)
Division of Air Resources Management

FACILITY DESCRIPTION

When complete, the new Bayside Power Station will have a nominal electrical production capacity of approximately 1742 MW. The following table summarizes the emission units and current status upon issuance of this air construction permit.

EU No.	Status [a]	Emission Unit Description
001	A [d]	Gannon Unit 1 – 125 MW coal fired boiler with steam electrical generator
002	A [d]	Gannon Unit 2 – 125 MW coal fired boiler with steam electrical generator
003	A [d]	Gannon Unit 3 – 180 MW coal fired boiler with steam electrical generator
004	A [d]	Gannon Unit 4 – 188 MW coal fired boiler with steam electrical generator
005	A [b, d]	Gannon Unit 5 – 239 MW coal fired boiler with steam electrical generator
006	A [c, d]	Gannon Unit 6 – 414 MW coal fired boiler with steam electrical generator
007	A	Combustion Turbine No. 1 – 14 MW simple cycle gas turbine
008	A	Gannon Station Coal Yard - Serves Gannon Units 1 – 6
009	A	Economizer Ash Silo w/Baghouse – Serves Gannon Unit No. 4
010	A	Fly Ash Silo No. 1 w/Baghouse – Serves Gannon Units 5 and 6
011	A	Fly Ash Silo No. 2 w/Baghouse – Serves Gannon Units 1 – 4
012	A	Pug Mill and Truck Unloading – Serves Gannon Units 5 and 6
013	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 1
014	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 2
015	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 3
016	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 4
017	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 5
018	A	Coal Bunker w/Roto-Clone – Serves Gannon Unit 6
019	I	Inactive emission unit
020	C [b]	Bayside Unit 1A – 170 MW combined cycle gas turbine
021	C [b]	Bayside Unit 1B – 170 MW combined cycle gas turbine
022	C [b]	Bayside Unit 1C – 170 MW combined cycle gas turbine
023	C [c]	Bayside Unit 2A – 170 MW combined cycle gas turbine
024	C [c]	Bayside Unit 2B – 170 MW combined cycle gas turbine
025	C [c]	Bayside Unit 2C – 170 MW combined cycle gas turbine
026	C [c]	Bayside Unit 2D – 170 MW combined cycle gas turbine
027	A	Distillate Oil Storage Tank - 8 million gallon capacity serves Bayside Units

Notes:

a. Status: A (Active), I (Inactive), C (Under Construction)

b. EU 005 must be shutdown before operating EUs 020, 021, and 022.

c. EU 006 must be shutdown before operating EU 023, 024, 025, and 026

d. EUs 001, 002, 003, 004, 005, and 006 must be shut down before January 1, 2005.

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). The MACT applicability determination for this project is deferred until one new combined cycle gas turbine is tested for HAP emissions.

Title IV: The facility has several emissions units, including the new combined cycle gas turbines, that are subject to the Acid Rain provisions of the Clean Air Act.

Title V: The existing facility is a Title V major source of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PPSC: The existing Gannon Station was constructed prior to the power plant site certification requirements of Chapter 62-17, F.A.C. The re-powering project is not subject to power plant site certification because there will be no expansion of the steam electrical generating capacity.

PSD: This facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the industries listed as one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is "major" with respect to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

NESHAP: The permittee did not identify any emission unit as being subject to a National Emissions Standard for Hazardous Air Pollutants (NESHAP).

NSPS: The new combined cycle gas turbines are subject the New Source Performance Standards (NSPS) of 40 CFR 60, Subpart GG and the oil storage tank is subject to 40 CFR 60, Subpart Kb.

RELEVANT DOCUMENTS

- DEP/TEC Consent Final Judgment signed in December of 1999;
- EPA/TEC Consent Decree signed in February of 2000; and
- PSD permit application received on September 21, 2000 and all related correspondence.

ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authorities: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Southwest District Office, Florida Department of Environmental Protection, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218. The phone number is 813/744-6100 and the fax number is 813/744-6084. Copies of all such documents shall be submitted to the Air Management Division of the Hillsborough County Environmental Protection Commission, 1410 North 21 Street, Tampa, FL 33605. The phone number is 813/272-5530 and the fax number is 813/272-5605.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. *Appendix A* lists frequently used abbreviations and explains the format used to cite rules and regulations in this permit.

4. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. Such an extension does not relieve the permittee from any applicable requirement of the DEP/TEC Consent Final Judgement or the EPA/TEC Consent Decree. [40 CFR 52.21(r)(2)]

7. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. Such an extension does not relieve the permittee from any applicable requirement of the DEP/TEC Consent Final Judgement or the EPA/TEC Consent Decree. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with an extension of the 18 month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]

9. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The

Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. 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. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least ninety days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation, and copies to each Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

EMISSIONS AND CONTROLS

13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

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

15. 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.]

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

TESTING REQUIREMENTS

17. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.

18. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. **Required Sampling Time**. 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. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

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

c. **Calibration of Sampling Equipment**. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

19. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

20. Calculation of Emission Rate: For each emissions performance test, 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.]

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

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)(b), F.A.C.]

22. 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)(b), F.A.C.]

RECORDS AND REPORTS

23. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

24. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to each Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

25. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

A. Combined Cycle Gas Turbines

This section of the permit addresses the following new emissions units.

EU ID	Bayside ID	Common Emission Unit Description
020 021 022 023 024 025 026	1A 1B 1C 2A 2B 2C 2D	Combined Cycle Gas Turbine: Each 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. The project also includes electric fuel heaters and cooling towers. Natural gas is the primary fuel with very low sulfur distillate oil as a limited backup fuel. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. NOx emissions are reduced by a Selective Catalytic Reduction (SCR) system combined with dry low-NOx (DLN) combustion technology when firing natural gas and with water injection when firing very low sulfur distillate oil as a backup fuel. At a compressor inlet air temperature of 59° F and firing 1842 mmBTU (HHV) per hour of natural gas, each unit produces approximately 169 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,020,000 acfm at 215° F. At a compressor inlet air temperature of 59° F and firing 1995 mmBTU (HHV) per hour of very low sulfur distillate oil, each unit produces approximately 182 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,160,000 acfm at 275° F. Bayside Units 1A, 1B, and 1C supply steam to a single steam electrical generator (formerly serving Gannon Unit 5) with a nameplate rating of 239 MW. Bayside Units 2A, 2B, 2C, and 2D supply steam to a single steam electrical generator (formerly serving Gannon Unit 6) with a nameplate rating of 414 MW of electrical power.

Applicable Standards and Regulations

1. BACT Determinations: The emissions units addressed in this section are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), particulate matter, (PM/PM_{10}), and volatile organic compounds (VOC). [Rule 62-212.400(BACT), F.A.C.]

2. MACT Determination: The MACT applicability determination for this project is deferred until a combined cycle gas turbine is tested for HAP emissions in accordance with Condition No. 23 of this section. However, the permittee shall plan accordingly for the possibility of future applicable controls. If additional controls are later required, the Department shall allow the permittee a reasonable time to install equipment and conform to new or additional conditions. [Rules 62-4.080 and 62-204.800(10)(d), F.A.C.; Section 112(g), CAAA.]

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

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

   b. **Subpart GG, Standards of Performance for Stationary Gas Turbines** as specified in *Appendix GG* of this permit.

EQUIPMENT

4. Schedule: Bayside Unit 1 is scheduled for completion in March 2003. Bayside Unit 2 is scheduled for completion in March 2004. The permittee shall inform the Department of any substantial changes to the construction schedule. [Application; Rule 62-212.400, F.A.C.]

5. Combined Cycle Gas Turbines: The permittee is authorized to install, tune, operate and maintain seven new General Electric Model PG7241(FA) gas turbines with electrical generator sets, each designed to produce a nominal 170 MW of *direct* electrical power. Each unit shall be designed as a combined cycle system to include an automated gas turbine control system, an inlet air filtration 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. [Applicant Request; Design]

6. Heat Recovery Steam Generators (HRSG): The preliminary design of the HRSGs provides three levels of steam conditions when firing natural gas (high pressure, intermediate pressure, and low pressure) and two levels of steam conditions when firing very low sulfur distillate oil as a backup fuel (high pressure and intermediate pressure). The Bayside 1 Unit HRSGs will be identical and the Bayside 2 Unit HRSGs will be identical. The permittee shall submit the final design data upon completion. [Design]

7. Automated Control System: The permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ Mark VI automated gas turbine control system for each combined cycle unit. Each system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, temperatures, heat input, and fully automated startup/shutdown. [Design; 62-212.400(BACT), F.A.C.]

8. 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 control NOx emissions from each combined cycle gas turbine. Prior to the initial emissions performance tests for each gas turbine, the dry low-NOx combustors and automated gas turbine control system shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize these pollutant emissions. The permittee shall provide at least 5 days advance notice prior to any tuning session.[Design; Rule 62-212.400(BACT), F.A.C.]

9. Selective Catalytic Reduction (SCR) System: The permittee shall install, tune, operate and maintain an SCR system to control NOx emissions from each combined cycle gas turbine. The SCR system consists of an ammonia injection grid, catalyst, anhydrous ammonia storage, monitoring and control system, electrical, piping and other support equipment. The SCR system shall be designed to control NOx emissions to the permitted levels with an ammonia slip no greater than 5 ppmvd corrected to 15% oxygen when firing natural gas and no greater than 9 ppmvd corrected to 15% oxygen when firing distillate oil. [DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree; Rule 62-4.070(3), F.A.C.]

10. Evaporative Inlet Air-Cooling System: Each combined cycle gas turbine may have an evaporative cooling system designed to reduce the temperature of the inlet air to the gas turbine compressor. The reduced temperature provides a greater mass flow rate and increase in power production with additional fuel combustion. The preliminary design is for a water distribution system with packed media blocks of corrugated layers of fibrous material. Air passing over the system wicks moisture away from the media to create the cooling effect. The permittee shall submit the final design data upon completion. [Applicant Request; Design]

PERFORMANCE RESTRICTIONS

11. Permitted Capacity: The maximum heat input rates to each gas turbine shall not exceed the following:

a. **Natural Gas Firing**: 1842 mmBTU per hour with a compressor inlet air temperature of 59° F and producing approximately 170 MW.

b. **Distillate Oil Firing**: 1995 mmBTU per hour with a compressor inlet air temperature of 59° F and producing approximately 182 MW.

The heat input rates are based on the higher heating values (HHV) of each fuel and accommodate expected performance levels in addition to the manufacturer's guarantee. 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. [Design; Rule 62-210.200(PTE), F.A.C.]

12. Allowable Fuels: As the primary fuel, each combined cycle gas turbine shall fire pipeline-quality natural gas containing no more than 2 grains of sulfur per 100 standard cubic feet of natural gas. As a backup fuel, each combined cycle gas turbine may be fired with very low sulfur No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight. No other fuels are allowed. [Design; Rules 62-210.200(PTE); DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree]

13. Operation: After completion of Bayside Unit 1, the permittee shall fully dispatch Bayside Unit 1 before operating any remaining Gannon unit. After completion of Bayside Units 1 and 2, the permittee shall fully dispatch Bayside Units 1 and 2 before operating any remaining Gannon unit. [DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree]

14. Restricted Operation: The hours of operation for each combined cycle gas turbine are not limited (8760 hours per year). However, very low sulfur distillate oil may only be fired as a backup fuel, provided:

    a. The unit cannot fire natural gas;

    b. The unit fires No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight as the backup fuel;

    c. The unit fires no more than 11,775,000 gallons of very low sulfur distillate oil during any consecutive 12 months (equivalent to 875 hours per year of oil firing).

    d. All air pollution controls are functional and used to the maximum extent possible for the unit; and

    e. The unit is in compliance with the emissions standards of this permit.

    [Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.; EPA/TEC Consent Decree]

15. 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 combined cycle 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 of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

{Permitting Note: A summary table of the emissions standards is provided in Appendix B of this permit.}

16. 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 a compressor inlet temperature of 59° F. For comparison to the standard, actual

measured mass emissions shall be corrected to a compressor inlet temperature of 59° F with manufacturer's data on file with the Department.

a. **Ammonia Slip**: Each SCR system shall be designed and operated for a maximum ammonia slip of no more than 5 ppmvd corrected to 15% oxygen when firing natural gas and no more than 9 ppmvd corrected to 15% oxygen when firing distillate oil. [Rule 62-4.070(3), F.A.C.]

b. **Carbon Monoxide (CO)**: When firing natural gas, CO emissions shall not exceed 28.7 pounds per hour and 7.8 ppmvd corrected to 15% oxygen. When firing distillate oil, CO emissions shall not exceed 64.5 pounds per hour and 15.0 ppmvd corrected to 15% oxygen. Compliance shall be based on a 3-run test average as determined by EPA Method 10. Certified CEM system data may be used to demonstrate compliance with this standard. [Rule 62-212.400(BACT), F.A.C.]

c. **Nitrogen Oxides (NOx)**: When firing natural gas, NOx emissions shall not exceed 23.1 pounds per hour and 3.5 ppmvd corrected to 15% oxygen. When firing distillate oil, NOx emissions shall not exceed 79.2 pounds per hour and 12.0 ppmvd corrected to 15% oxygen. NOx emissions are defined as oxides of nitrogen measured as NO_2. Compliance shall be based on a 3-run test average as determined by EPA Methods 7E. Certified CEM system data may be used to demonstrate compliance with this standard. [DEP/TEC Consent Final Judgement; EPA/TEC Consent Decree; 40 CFR 60.332]

d. **Particulate Matter (PM/PM_{10})**: The fuel specifications in Condition No. 12 of this section combined with the efficient combustion design and operation of each combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for particulate matter. Compliance with the fuel specifications, CO standards, and visible emissions standards of this section shall serve as surrogate standards for particulate matter. {Permitting Note: Particulate matter emissions are expected to be less than 12 pounds per hour when firing natural gas and less than 30 pounds per hour when firing distillate oil, as determined by EPA Methods 5, front-half catch only.} [Rule 62-212.400(BACT), F.A.C.]

e. **Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2)**: The limits on fuel sulfur specified in Condition No. 12 of this section effectively limit the potential emissions of SO_2 and SAM. Compliance with the fuel sulfur limits shall be demonstrated by the fuel sampling, analysis, record keeping and reporting requirements of Condition No. 29 this section. [Design; 40 CFR 60.333]

f. **Visible Emissions**: When firing either natural gas or distillate oil, visible emissions shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. Except as allowed by Condition No. 19 of this section, this standard applies during all loads. [Rule 62-212.400(BACT), F.A.C.]

g. **Volatile Organic Compounds (VOC)**: The efficient combustion of clean fuels and good operating practices for each combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with the CO standards shall serve as surrogate standards for VOC emissions. {Permitting Note: VOC emissions are expected to be less than 3 pounds per hour (1.3 ppmvd corrected to 15% oxygen) when firing natural gas and less than 7.5 pounds per hour (3.0 ppmvd corrected to 15% oxygen) when firing distillate oil, as determined by EPA Method 25A measured and reported as methane.} [Design; Rule 62-212.400(BACT), F.A.C.]

17. <u>Emissions Standards Based on CEM System Data</u>: The following standards apply to each combined cycle gas turbine based on data collected from required Continuous Emissions Monitoring (CEM) systems.

a. **Carbon Monoxide (CO)**: When firing natural gas, CO emissions shall not exceed 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average. When firing distillate oil, CO emissions shall not exceed 20.0 ppmvd corrected to 15% oxygen based on a 24-hour block average.

b. **Nitrogen Oxides (NOx)**: When firing natural gas, NOx emissions shall not exceed 3.5 ppmvd corrected to 15% oxygen based on a 24-hour block average. When firing distillate oil, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 24-hour block average.

Each 24-hour block average shall start at midnight each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EXCESS EMISSIONS

18. 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 CO and NOx CEM system compliance averages. [Rule 62-210.700(4), F.A.C.]

19. Excess Emissions Defined: During startup, shutdown, and documented unavoidable malfunction of each combined cycle gas turbine, the following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of operation. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such incidents.

    (a) During startup and shutdown, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during any calendar day, which shall not exceed 20% opacity. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

    (b) Except for startup and shutdown, operation below 50% base load is prohibited.

    (c) A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more and the first stage turbine metal temperature is 250° F or less. To minimize emissions, no more than one gas turbine for each Bayside Unit shall be operated during such a startup. The permittee shall notify each Compliance Authority at least 24-hours in advance of a steam turbine cold startup.

    (d) In accordance with Condition No. 27 of this section, specific data collected by the CEM systems during startup, shutdown, malfunction, and tuning may be excluded from the CO and NOx compliance averaging periods. If a CEM system reports emissions in excess of a 24-hour block emissions standard, the permittee shall notify the Compliance Authority within (1) 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 Department may request a written summary report of the incident.

    (e) For each Bayside Unit, the permittee shall provide a Startup and Shutdown Plan as part of the application for a Title V air operation permit. The plan shall identify startup and shutdown procedures, duration of the procedures, and the methods used to minimize emissions during these periods. Within 90 days of completing the eighth steam turbine cold startup of a Bayside Unit, the permittee shall submit a revised plan to the Department based on actual operating data and experience. The Department shall review the actual operational data and determine whether the period of data exclusion for a steam turbine cold startup defined in Condition 27 of this section shall be *decreased* to represent good operational practices.

[Design; Rule 62-210.700; Rule 62-4.130, F.A.C.; Rule 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

20. Operating Rate During Testing: Testing of emissions 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. [Rule 62-297.310(2), F.A.C.]

21. Test Methods: Required tests shall be performed in accordance with the following reference methods.

EPA 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 • For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run. • For oil firing, the minimum sampling time shall be one hour per run and the minimum sampling volume shall be 30 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 be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
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 methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CT-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

22. Initial Compliance Tests: Each combined cycle gas turbine shall be tested when firing each authorized fuel to demonstrate compliance the emission standards for CO, NOx, visible emissions and ammonia slip. The tests must be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each combined cycle gas turbine. Tests for CO, NOx, and VOC shall be conducted concurrently. Certified CEM system data may be used to demonstrate compliance with the CO and NOx standards. The test results for ammonia slip shall also report the average NOx emissions during each test run. [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.335]

23. Initial HAP Performance Tests: At least one of the Bayside Unit 1 combined cycle gas turbines shall be tested when firing natural gas for total volatile organic compounds and the following hazardous air pollutant (HAP) emissions: acetaldehyde, formaldehyde, toluene, and xylene. EPA Method 25A shall be used to determine the emission rate of total volatile organic compounds and EPA Method 18 shall be used to determine the emission rate of each individual HAP. The tests must be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each combined cycle gas turbine. Tests shall be conducted at two operating rates: between 65% and 75% of permitted capacity and between 90% to 100% of permitted capacity. For each operating rate, the tests shall consist of at least three 1-hour runs and emissions shall be reported in terms of ppmvd corrected to 15% oxygen, pounds per million BTU, pounds per hour, and pound per MW-hour. The test report shall include the gas turbine exhaust temperature (prior to the heat recovery steam generator) and the average CO and NOx emissions recorded by the CEM systems. In addition, the test report shall include the permittee's revised MACT applicability analysis (based on the test data and current EPA guidance) and propose a Maximum Available Control Technology, if necessary.

24. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each combined cycle gas turbine shall be tested when firing natural gas to demonstrate compliance with the emission standards for ammonia slip and visible emissions. Each combined cycle gas turbine that fires more than 200 hours of distillate oil during the federal fiscal year shall also be tested for visible emissions and ammonia slip when firing oil. Compliance with the CO and NOx emissions standards shall be determined from data collected by the CEM systems during the required annual RATA. NOx emissions recorded by the CEM system during the test for ammonia slip shall be reported for each test run. [Rules 62-212.400(BACT) and 62-297.310(7)(a)4., F.A.C.]

25. Additional Ammonia Slip Testing: If the annual tested ammonia slip rate exceeds 4.5 ppmvd corrected to 15% oxygen when firing natural gas, the permittee shall begin testing and reporting the ammonia slip during each subsequent calendar quarter. If the ammonia slip exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas, the permittee shall take corrective action, test, and demonstrate compliance with the maximum ammonia slip rate within 180 days of first detection. When subsequent tests indicate the ammonia slip rate is less than 4 ppmvd corrected to 15% oxygen, testing shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

26. Tests After Substantial Modifications: The Department may require additional performance tests after any substantial modification and appropriate shakedown period of the gas turbines, including the replacement of dry low-NOx combustors, or modification of the air pollution control equipment. Shakedown periods shall not exceed 100 days after re-starting each combined cycle gas turbine. This does not apply to routine maintenance. [Rules 62-297.310(7)(a)4. and 62-4.070(3), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

27. Continuous Emission Monitoring System: The owner or operator shall install, calibrate, maintain, and operate a continuous emission monitoring (CEM) system in the exhaust stack of each emissions unit to measure and record the emissions of NOx and CO from these emissions units in a manner sufficient to demonstrate compliance with the CEM emission standards of this permit. The oxygen content or the carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where NOx and CO are monitored to correct the measured CO and NOx emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEM system using F-factors that are appropriate for the fuel fired. The CEM system shall be used to demonstrate compliance with the CEM emission standards for NOx and CO specified in this permit.

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

b. *NOx Certification.* The NOx monitor shall be certified and operated in accordance with the following requirements. 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 CEM emission standards of this permit, missing data shall not be substituted. Instead the 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 20 or 7E, of Appendix A of 40 CFR 60. The NOx monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

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

d. *Data Exclusion.* Emissions data for NOx, CO and CO_2 (or oxygen content) shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NOx and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards as provided in this paragraph.

(1) Periods of data excluded for gas turbine startup (excluding steam turbine cold startup), shutdown, or documented unavoidable malfunction shall not exceed two hours in any 24-hour block period. Periods of data excluded for such episodes shall not exceed a total of four hours in any 24-hour block period. Gas turbine startup is the commencement of operation of a gas turbine which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, or pollution control device imbalances, which may result in elevated emissions. Shutdown is the process of bringing a gas turbine off line and ending fuel combustion. A documented unavoidable malfunction is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

(2) Periods of data excluded for a steam turbine cold startup shall not exceed sixteen hours in any block 24-hour block period. A "steam turbine cold startup" is defined as startup after the steam turbine has been offline for 24 hours or more and the first stage turbine metal temperature is 250° F or less. Based on actual operating experience and data, the Department may *decrease* this period of data exclusion in the Title V air operating permit without modifying this PSD permit.

(3) If the permittee provides at least five days advance notice prior to a tuning session, data may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards. Periods of data excluded for such episodes shall not exceed a total of three hours in any 24-hour block period. Tuning sessions must be performed in accordance with the manufacturer's recommendations. No more than two tuning sessions are expected during any year.

All periods of data excluded for any startup, shutdown or malfunction episode 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 events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

e. *Data Exclusion Reports.* A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported semi-annually to each Compliance Authority. This report shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, as allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur.

f. *Data Conversion.* Upon request from the Department, the CEM systems emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

g. *Availability.* NOx and CO monitor availability shall not be less than 95% in any calendar quarter.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEM system 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.}

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

28. 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 to each SCR system. The permittee shall document the general range of ammonia flow rates required to meet emissions limitations over the range of combustion turbine load conditions allowed by 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 combustion turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS

29. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    b. Compliance with the fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

30. Monitoring of Operations: To demonstrate compliance with the fuel consumption limits, the permittee shall monitor and record the rates of consumption of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. To demonstrate compliance with the turbine capacity requirements, the permittee shall monitor and record the operating rate of each combined cycle 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 CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

31. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the monthly fuel consumption and hours of operation for each gas turbine. The information shall be recorded in a written (or electronic log) and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. [Rule 62-4.070(3), F.A.C.]

B. STORAGE TANK

This section of the permit addresses the following emissions unit.

EU ID	Emission Unit Description
027	Oil Storage Tank: Existing eight million gallon storage tank supplies low sulfur distillate oil as a backup fuel to the combined cycle gas turbines (EUs 020 through 026).

RULE APPLICABILITY

1. NSPS Subpart Kb Applicability: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(a)]

2. Exemption from Portions of NSPS Subpart Kb: Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified below. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(c)]

PERFORMANCE REQUIREMENTS

3. Equipment: The existing 8 million gallon tank shall provide storage for the very low sulfur distillate oil used as backup fuel for the combined cycle gas turbines. [Applicant Request]

4. Hours of Operation: Operation for the distillate oil storage tank is not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

RECORDS

5. Records: For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual throughput of distillate oil through the storage tank. [Rule 62-210.370(3), F.A.C.]

6. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the facility. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.116b(a) and (b)]

C. Existing Emissions Units

The following conditions supplement all other valid air construction and operation permits for these units.

EU No.	Emission Unit Description
001	Gannon Unit 1 – 125 MW coal fired boiler with steam electrical generator
002	Gannon Unit 2 – 125 MW coal fired boiler with steam electrical generator
003	Gannon Unit 3 – 180 MW coal fired boiler with steam electrical generator
004	Gannon Unit 4 – 188 MW coal fired boiler with steam electrical generator
005	Gannon Unit 5 – 239 MW coal fired boiler with steam electrical generator
006	Gannon Unit 6 – 414 MW coal fired boiler with steam electrical generator
008	Gannon Station Coal Yard - Serves Gannon Units 1 – 6

Shutdown Requirements

1. Shutdown of Gannon Unit 5: Gannon Unit 5 (EU-005) shall be shut down and rendered incapable of operation prior to first fire in any combined cycle gas turbine for Bayside Unit 1 (EU 020 – EU 022). Upon first fire in any combined cycle gas turbine for Bayside Unit 1, the heat input limit on the coal yard (EU-008) is reduced to 56.7×10^{-06} mmBTU per consecutive 12 months. [Rule 62-212.400(BACT), F.A.C.]
2. Shutdown of Gannon Unit 6: Gannon Unit 6 (EU-006) shall be shut down and rendered incapable of operation prior to first fire in any combined cycle gas turbine for Bayside Unit 2 (EU 023 – EU 026). Upon first fire in any combined cycle gas turbine for Bayside Unit 2, the heat input limit on the coal yard (EU-008) is reduced to 35.3×10^{-06} mmBTU per consecutive 12 months. [Rule 62-212.400(BACT), F.A.C.]
3. Shutdown of Gannon Units 1 - 6: The permittee shall shutdown and cease any and all operation of coal-fired Gannon Units 1 - 6 (EU 001 - 006) no later than December 31, 2004. "Shutdown" shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel (including wood-derived fuel) nor produce any steam for electricity production, other than through re-powering as specified in this permit. [EPA/TEC Consent Decree]
4. Permanent Bar on Combustion of Coal: Commencing on January 1, 2005, the permittee shall not combust coal in the operation of any unit at this plant. [EPA/TEC Consent Decree]
5. Notification: Before January 1, 2005, the permittee shall notify the Department of plans for the coal storage and handling facilities. Additional permits may be required. [Rule 62-210.300, F.A.C.]
6. Revisions or Extensions: The provisions of this section shall not be extended or revised the without prior written approval of the U.S. EPA. [EPA/TEC Consent Decree]

SECTION IV. APPENDIX A

TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

CCGT	-	Combined Cycle Gas Turbine
CEM	-	Continuous Emissions Monitor
DARM	-	Division of Air Resource Management
DEP	-	State of Florida, Department of Environmental Protection
DLN	-	Dry Low-NOx Combustion Technology
EPA	-	United States Environmental Protection Agency
°F	-	Degrees Fahrenheit
F.A.C.	-	Florida Administrative Code
F.S.	-	Florida Statute
HRSG	-	Heat Recovery Steam Generator
UTM	-	Universal Transverse Mercator
SCR	-	Selective Catalytic Reduction

FORMATS FOR PERMIT REFERENCES AND RULE CITATIONS

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, permit numbers, and identification numbers.

Florida Administrative Code (F.A.C.) Rules:

Example: [Rule 62-213.205, F.A.C.]
Where: 62 - identifies the specific Title of the F.A.C.
62-213 - identifies the specific Chapter of the F.A.C.
62-213.205 - identifies the specific Rule of the F.A.C.

Facility Identification (ID) Number:

Example: Facility ID No. 099-0001
Where: 099 - identifies the specific county location
0221 - identifies the specific facility

New Permit Numbers:

Example: Permit No. 099-2222-001-AC or 099-2222-001-AV
Where: AC - identifies the permit as an Air Construction Permit
AV - identifies the permit as a Title V Major Source Air Operation Permit
099 - identifies the specific county that project is located in
2222 - identifies the specific facility
001 - identifies the specific permit project

Old Permit Numbers:

Example: Permit No. AC50-123456 or AO50-123456
Where: AC - identifies the permit as an Air Construction Permit
AO - identifies the permit as an Air Operation Permit
123456 - identifies the specific permit project

SECTION IV. APPENDIX B

SUMMARY OF BACT AND EMISSIONS STANDARDS

For informational purposes, the following table summarizes the standards specified in this permit.

Table B-1. Summary of Emissions Standards for Bayside Units 1 and 2

Pollutant	Gas Firing	Oil Firing
Standards Based on Emissions Performance Tests (Based on permitted capacity and an inlet temperature of 59° F)		
Ammonia	5 ppmvd @ 15% O_2	9 ppmvd @ 15% O_2
CO (BACT)	7.8 ppmvd @ 15% O_2 28.7 lb/hr	15.0 ppmvd @ 15% O_2 64.5 lb/hr @ 59° F
Fuel Specification (BACT)	Natural Gas: 2 grains sulfur per 100 SCF	Distillate Oil: 0.05% sulfur by weight
NOx	3.5 ppmvd @ 15% O_2 23.1 lb/hr	12.0 ppmvd @ 15% O_2 79.2 lb/hr @ 59° F
PM/PM_{10} (BACT)	Fuel Specifications 10% Opacity, 6-minute average CO standard is a surrogate. {Estimated maximum is 12 lb/hr.}	Fuel Specifications 10% Opacity, 6-minute average CO standard is a surrogate. {Estimated maximum is 30 lb/hr.}
SAM/SO_2	Fuel Specifications	Fuel Specifications Oil use limited to equivalent of 875 hr/yr.
VOC (BACT)	Efficient combustion and operating practices CO standard is a surrogate. {Estimated maximum is 3.0 lb/hr, equivalent to 1.3 ppmvd @ 15% O_2.}	Efficient combustion and operating practices CO standard is a surrogate. {Estimated maximum is 7.5 lb/hr, equivalent to 3.0 ppmvd @ 15% O_2.}
Standards Based on CEMS Data		
CO (BACT)	9.0 ppmvd @ 15% O_2, 24-hr block avg.	20.0 ppmvd @ 15% O_2, 24-hr block avg.
NOx	3.5 ppmvd @ 15% O_2, 24-hr block avg.	12.0 ppmvd @ 15% O_2, 24-hr block avg.

Notes:

- NOx emissions are controlled by and SCR system combined with dry low-NOx combustion when firing gas and combined with water injection when firing oil.
- A detailed description of the BACT evaluation is presented in the Technical Evaluation and Preliminary Determination.
- Construction is scheduled to begin in April of 2001. First firing is scheduled for March of 2003 for Bayside Units 1A, 1B, and 1C. First firing is scheduled for March of 2004 for Bayside Units 2A, 2B, 2C, and 2D.

BACT DETERMINATIONS

The project resulted in significant net increases of actual emissions of carbon monoxide (CO) and volatile organic compounds (VOC). Based on an interpretation by EPA Region 4, emissions of particulate matter (PM/PM_{10}) would also be significant if BACT controls had previously been installed on existing Gannon Units 5 and 6. For CO, PM, and VOC emissions, the Department determined that the efficient combustion of clean fuels and good operating practices represent BACT for the combined cycle units. A continuous monitoring system is required for CO emissions to demonstrate continuous compliance with the corresponding CO standard and as surrogate standards for PM and VOC emissions.

SECTION IV. APPENDIX B

SUMMARY OF BACT AND EMISSIONS STANDARDS

The Department's technical review and rationale for the determinations of Best Available Control Technology (BACT) are presented in Technical Evaluation and Preliminary Determination issued on (DRAFT) with the Draft Permit.

Determination By:

(DRAFT)

J. F. Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

(DRAFT)

C. H. Fancy, Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

H. L. Rhodes, Director (Date)
Division of Air Resources Management

Table E. Summary of Mass Emissions for Given Compressor Inlet Temperatures

Pollutant	Inlet Temp.	Mass Emission Rate, lb/hour	
		Gas Firing	Oil Firing
CO	18° F	31.1	70.0
	35° F	30.0	68.0
	59° F	28.7	64.5
	72° F	27.8	62.5
	93° F	26.9	60.4
NOx	18° F	24.7	96.8
	35° F	23.8	94.3
	59° F	23.1	90.9
	72° F	22.6	89.0
	93° F	21.9	86.0
PM/PM10	18° F	11.5	29.0
	35° F	11.4	28.6
	59° F	11.3	28.0
	72° F	11.3	27.6
	93° F	11.2	27.1
VOC	18° F	3.0	7.8
	35° F	3.0	7.5
	59° F	2.8	7.3
	72° F	2.7	7.1
	93° F	2.7	6.9

Notes:

- NOx emissions standards for emissions controlled by an SCR system.
- PM are based on EPA Method 5 (front-half catch only).

GENERAL CONDITIONS

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

(a) Have access to and copy and records that must be kept under the conditions of the permit;
(b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
(c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

(a) A description of and cause of non-compliance; and
(b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections

403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (Yes, for CO, PM/PM10, and VOC);

(b) Determination of Prevention of Significant Deterioration (Yes); and

(c) Compliance with New Source Performance Standards (Yes with Subparts GG and Kb).

G.14 The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

NSPS Subpart GG Requirements

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

11. 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)
$N \le 0.015$	0
$0.015 < N \le 0.1$	0.04(N)
$0.1 < N \le 0.25$	0.004+0.0067(N−0.1)
$N > 0.25$	0.005

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

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

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

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

12. Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

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

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

13. Pursuant to 40 CFR 60.334 Monitoring of Operations:

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

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

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

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

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

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

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

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

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

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

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

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

14. Pursuant to 40 CFR 60.335 Test Methods and Procedures:

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

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as 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 required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

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

<u>Department requirement</u>: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

<u>Department requirement</u>: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

<u>Department requirement</u>: The permit species sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

SECTION IV. APPENDIX XS

SEMI-ANNUAL CONTINUOUS MONITOR SYSTEMS REPORT

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

Pollutant *(Circle One)*: SO_2 NO_x TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ______________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ______________________________

Date of Latest CMS Certification or Audit: ____________________________

Process Unit(s) Description: ______________________________________

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

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

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

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

Note: *On a separate page, describe any changes to CMS, process or controls during last 6 months.*

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

____
Name

____
Title

____ ____________________
Signature *Date*

Florida Department of

Memorandum Environmental Protection

TO: Clair Fancy, Chief – Bureau of Air Regulation

THROUGH: Al Linero, Administrator - New Source Review Section 2/2

FROM: Jeff Koerner, Project Engineer - New Source Review Section JK

DATE: February 1, 2001

PROJECT: Tampa Electric Company
Bayside Power Station (Gannon Re-Powering Project)
Project No. 0570040-013-AC
Draft Permit No. PSD-FL-301

Attached is the intent to issue permit and public notice package to re-power the existing Gannon power plant located on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and consists of seven new gas-fired combined cycle gas turbine units. The nominal electric generating capacity for this site will increase from approximately 1100 MW to approximately 1700 MW. My attached P.E. certification provides a brief summary of the required controls and emissions standards. The attached Technical Evaluation and Preliminary Determination provides a detailed analysis of the project.

Day #74 of the permitting time clock is March 9, 2001. I recommend your approval of the attached Draft Permit.

CHF/AAL/jfk
Attachments

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT

PERMITTEE

Tampa Electric Company – Bayside Power Station
Port Sutton Road
Tampa, FL 33619

Project No.	0570040-013-AC
Draft Permit No.	PSD-FL-301
Facility ID No.	0570040
SIC No.	4911

PROJECT DESCRIPTION

The Tampa Electric Company (TEC) owns and operates the F.J. Gannon Station located on Tampa's Port Sutton Road in Hillsborough County, Florida. TEC proposes to re-power the existing Gannon Station with seven new combined cycle gas turbines in accordance with the DEP/TEC Consent Final Judgment signed in December of 1999 and with the EPA/TEC Consent Decree signed in February of 2000. Each unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. Steam from three new combined cycle units (Bayside Units 1A, 1B, and 1C) will re-power existing Gannon steam-electric turbine No. 5 (nameplate rating of 239 MW). Steam from four new combined cycle units (Bayside Units 2A, 2B, 2C, and 2D) will re-power existing Gannon steam-electric turbine No. 6 (nameplate rating of 414 MW). An existing 14 MW simple cycle gas turbine will remain on site. All existing coal-fired boilers (Gannon Units 1 – 6) will be shut down prior to January 1, 2005. The re-powered plant will have an electrical production capacity of approximately 1700 MW.

The project will result in significant net increases in actual emissions of CO and VOC. Based on EPA Region 4's interpretation of netting for this project, it is also significant for emissions PM/PM_{10}. The Best Available Control Technology (BACT) for each of these pollutants is determined to be the efficient combustion of clean fuels. Pipeline-quality natural gas is the primary fuel and very low sulfur distillate oil (< 0.05% sulfur by weight) is the backup fuel. Each unit may fire may fire up to 875 hours of distillate oil per year, but only if natural gas cannot be fired in the unit. The state and federal settlement agreements specified installation of the SCR systems. NOx emissions are controlled by an SCR system combined with dry low-NOx combustion technology when firing natural gas and combined with water injection when firing oil. Each combined cycle unit will have CO and NOx continuous emissions monitoring systems to demonstrate compliance. The CO emissions standards serve as surrogate standards for emissions of PM/PM_{10} and VOC.

After shutdown of the coal-fired units, it is estimated that the Bayside project will reduce *actual* emissions of nitrogen oxides by more than 28,000 tons per year, particulate matter by more than 1000 tons per year, and sulfur dioxide by more than 60,000 tons per year. Although not specifically required for each pollutant, the emissions standards specified in the Draft Permit for CO, NOx, PM/PM_{10}, SO_2, and VOC represent BACT-level controls. In addition, the CO and NOx emissions monitors will provide a continuous demonstration of compliance with the standards and efficient combustion of each unit.

***I HEREBY CERTIFY** that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

Jeffery F. Koerner
Jeffery F. Koerner, P.E.
Registration Number: 49441

02-01-01
(Date)

DARM/BAR - New Source Review Section
Florida Department of Environmental Protection

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