Memorandum

Florida Department of Environmental Protection

TO: Michael G. Cooke, Division of Air Resource Management

THRU: Trina Vielhauer, Bureau of Air Regulation
Al Linero, Air Permitting South Program

aal

FROM: Jeff Koerner, Air Permitting South Program

DATE: March 7, 2005

SUBJECT: Air Permit No. PSD-FL-301C
Project No. 0570040-019-AC
Tampa Electric Company - H. L. Culbreath Bayside Power Station
Simple Cycle Phase and Restricted Oil Firing

The Final Permit for this project is attached for your approval and signature, which authorizes: a phase of simple cycle operation for Bayside Units 3A and 3B; distillate oil as a restricted alternate fuel for Bayside Units 3A and 3B during simple cycle operation; distillate oil as an emergency backup fuel for Bayside Units 3A and 3B once converted to combined cycle operation; and an extension of the expiration date to allow construction of Bayside Units 3 and 4 as combined cycle units. The H. L. Culbreath Bayside Power Station is located in Tampa at 3602 Port Sutton Road in Hillsborough County, Florida. The project is subject to PSD preconstruction review for CO, PM/PM_{10}, and VOC emissions.

The Department distributed an "Intent to Issue Permit" package on December 30, 2004. The applicant published the "Public Notice of Intent to Issue" in the Tampa Tribune on January 17, 2005. The Department received the proof of publication on January 21, 2005. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed. Based on comments from the applicant received on February 15, 2005, only minor changes were made to the permit as described in the attached Final Determination.

Day #90 is March 28, 2005. I recommend your approval of the attached Final Permit for this project.

Attachments

FINAL DETERMINATION

PERMITTEE

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

PERMITTING AUTHORITY

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

PROJECT

Air Permit No. PSD-FL-301C
Project No. 0570040-019-AC
H. L. Culbreath Bayside Power Station

The Tampa Electric Company operates the H. L. Culbreath Bayside Power Station in Tampa at 3602 Port Sutton Road in Hillsborough County, Florida. The electrical power plant (SIC No. 4911) was formerly known as the F. J. Gannon Station, but was re-powered with combined cycle gas turbines firing natural gas. This permit revision authorizes: a phase of simple cycle operation for Bayside Units 3A and 3B; distillate oil as a restricted alternate fuel for Bayside Units 3A and 3B during simple cycle operation; distillate oil as an emergency backup fuel for Bayside Units 3A and 3B once converted to combined cycle operation; and an extension of the expiration date to allow construction of Bayside Units 3 and 4 as combined cycle units.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on December 30, 2004. The applicant published the "Public Notice of Intent to Issue" in the Tampa Tribune on January 17, 2005. The Department received the proof of publication on January 21, 2005. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed.

COMMENTS

No comments on the Draft Permit were received from the public, the Department's Southwest District Office, the Environmental Protection Commission of Hillsborough County, EPA Region 4, or the National Park. The Department received comments from the applicant on February 15, 2005. The following summarizes the applicant's comments and the Department's response.

Condition C.3.b - Construction

Comment: TECO does not believe that revalidation of the BACT or a new netting analysis should be required if a permit extension is required when the project is near completion. TECO requests the following revision, "Conversion of Units 3A and 3B to combined cycle operation shall be complete before this permit expires. TEC may request an extension of the expiration date of the permit. If an extension is granted based upon an adequate justification, the original BACT determinations and netting analyses shall remain unchanged. Upon review, the Department may require validation of the BACT determinations and a new netting analysis. ~~Otherwise, the Department will require revalidation of the BACT determinations and a new netting analysis for any requests to extend the permit.~~"

Response: It is acknowledged that there may be circumstances in which construction of the gas turbines systems is nearly complete and revalidation of the BACT determinations or a revised PSD netting analysis is not warranted. The condition was revised as follows:

"3. Construction: Bayside Unit 3 is scheduled to commence construction in May of 2005 and complete construction in 2006. Units 3A and 3B may be installed and operated as simple cycle units and later converted to combined cycle units. Unit 4 will be added as a combined cycle unit. The permittee shall inform the Department and Compliance Authority of any substantial changes to the construction schedule including conversion of Units 3A and 3B to combined cycle operation. Pursuant to 40 CFR 52.21(r)(2):

a. Construction of Bayside Units 3A and 3B shall commence within 18 months after permit issuance. Otherwise, authorization to construct shall become invalid.

b. Conversion of Units 3A and 3B to combined cycle operation shall be complete before this permit expires. ~~Otherwise, the Department will require revalidation of the BACT determinations and a new netting analysis for any requests to extend the permit.~~

c. Construction of combined cycle Unit 4 shall be complete before this permit expires. ~~Otherwise, the Department will require revalidation of the BACT determinations and a new netting analysis for any requests to extend the permit.~~

d. Each combined cycle unit shall include an SCR system to reduce NOx emissions.

e. For good cause, the permittee may request that this PSD air construction permit be extended. When processing any request for a permit extension, the Department may require revalidation of the BACT determinations or a revised netting analysis or both.

[Application; Rule 62-212.400(BACT), F.A.C.]"

Condition C.11.c – Distillate Oil

Comment: Upon conversion of Units 3A and 3B to combined cycle operation, the EPA/TECO Consent Decree allows up to 875 equivalent full load hours on No. 2 oil if the unit cannot be fired with natural gas. The draft permit recognizes the requirements of the EPA/TECO Consent Decree, but continues to limit oil firing after conversion to combined cycle operation to the level requested for simple cycle operation (700 full load equivalent hours). Once the units are converted to combined cycle operation, TECO requests that oil firing be allowed for up to 875 equivalent full load hours. TECO also requests that the requirements of the EPA/TECO Consent Decree be referenced and not included in the permit.

Response: A review of the Technical Evaluation issued in support of the draft PSD permit shows that the PSD netting analysis was actually based on 875 equivalent full load hours for oil firing. In addition, it is recognized that the ability to fire oil after conversion to combined cycle operation is narrowly restricted by the requirements of the EPA/TECO Consent Decree to only those periods when the unit cannot be fired with natural gas. Therefore, the Department revised the condition to allow 875 equivalent full load hours after conversion to combined cycle operation. However, the oil firing requirements of the EPA/TECO Consent Decree were included verbatim in the permit. For clarity, the Department also added the text "During simple cycle operation, ..." to the sentence in Condition 11b that specifies the oil firing restriction of 700 full load equivalent hours of operation.

Condition C.12 – Restricted Operation

Comment: TECO requests that the title of this permit condition be revised from "Restricted Operation" to "Hours of Operation".

Response: The condition will be revised as requested.

Condition C.17 – Alternate Standards and Data Exclusions

Comment: For Units 3 and 4, the draft permit referenced the requirements in Section IIIA for Units 1 and 2. For clarity, TECO requests that the full text of these requirements be included for Units 3 and 4.

Response: The condition will be revised as requested. The revision will not result in any new or revised requirements.

Condition C.19 – Test Methods

Comment: For Units 3 and 4, the draft permit referenced the requirements in Section IIIA for Units 1 and 2. For clarity, TECO requests that the full text of these requirements be included for Units 3 and 4.

Response: The condition will be revised as requested. The revision will not result in any new or revised requirements.

Condition C.22 – Additional Ammonia Slip Testing

Comment: For Units 3 and 4, the draft permit referenced the requirements in Section IIIA for Units 1 and 2. For clarity, TECO requests that the full text of these requirements be included for Units 3 and 4.

Response: The condition will be revised as requested. The revision will not result in any new or revised requirements.

Condition C.23 – Continuous Emissions Monitoring Systems

Comment: For Units 3 and 4, the draft permit referenced the requirements in Section IIIA for Units 1 and 2. For clarity, TECO requests that the full text of these requirements be included for Units 3 and 4.

Response: The condition will be revised as requested. The revision will not result in any new or revised requirements.

Condition C.25 – Semiannual CEMS Report

Comment: For Units 3 and 4, the draft permit referenced the requirements in Section IIIA for Units 1 and 2. For clarity, TECO requests that the full text of these requirements be included for Units 3 and 4.

Response: The condition will be revised as requested. The revision will not result in any new or revised requirements.

Appendix B – Summary of BACT Determinations and Emissions Standards

Comment: Correct typographical error in 3rd paragraph, "... to install ~~a~~ selective catalytic reduction systems ..." Correct typographical error in 4th paragraph, "... to re-power Gannon Unit 4 ~~6~~."

Response: The typographical error was corrected.

Appendix B – Summary of Mass Emission Rates for Firing Natural Gas

Comment: Correct typographical error in 4th bullet, "... are measured as methane."

Response: The typographical error was corrected.

Appendix GG – NSPS Subpart GG Requirements for Gas Turbines

Comment: On page GG-3 in Department note under provision (d), correct "species" to "specifies."

Response: The typographical error was corrected.

CONCLUSION

The Department considers the changes and revisions to be minor in nature. The final action of the Department is to issue the permit with these changes.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

Authorized Representative:
Wade A. Maye, General Manager

H. L. Culbreath Bayside Power Station
Air Permit No. PSD-FL-301C
Project No. 0570040-019-AC
Hillsborough County, Florida

Enclosed is Final Air Permit No. PSD-FL-301C, which authorizes: a phase of simple cycle operation for Bayside Units 3A and 3B; distillate oil as a restricted alternate fuel for Bayside Units 3A and 3B during simple cycle operation; distillate oil as an emergency backup fuel for Bayside Units 3A and 3B once converted to combined cycle operation; and an extension of the expiration date to allow construction of Bayside Units 3 and 4 as combined cycle units. The H. L. Culbreath Bayside Power Station is located in Tampa at 3602 Port Sutton Road in Hillsborough County, Florida. As noted in the attached Final Determination, only minor changes and clarifications were made. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

for Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 3/15/05 to the persons listed:

Mr. Wade A. Maye, TECO*
Ms. Greer Briggs, TECO
Ms. Raisa Calderon, TECO
Mr. Tom Davis, P.E., ECT

Mr. Jerry Kissel, SWD Office
Mr. Jerry Campbell, HEPC
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

(Clerk) 3/15/05 (Date)

Department of Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

PERMITTEE:

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

Authorized Representative:
Wade A. Maye, General Manager

H. L. Culbreath Bayside Power Station
Air Permit No. PSD-FL-301C
Project No. 0570040-019-AC
Expires: December 31, 2007

PROJECT

The Tampa Electric Company operates the H. L. Culbreath Bayside Power Station in Tampa at 3602 Port Sutton Road in Hillsborough County, Florida. The electrical power plant (SIC No. 4911) was formerly known as the F. J. Gannon Station, but was re-powered with combined cycle gas turbines firing natural gas. This permit revision authorizes: a phase of simple cycle operation for Bayside Units 3A and 3B; distillate oil as a restricted alternate fuel for Bayside Units 3A and 3B during simple cycle operation; distillate oil as an emergency backup fuel for Bayside Units 3A and 3B once converted to combined cycle operation; and an extension of the expiration date to allow construction of Bayside Units 3 and 4.

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 and perform the work 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/TECO Consent Final Judgment or the EPA/TECO Consent Decree.

Michael G. Cooke, Director
Division of Air Resource Management

Effective Date

FACILITY DESCRIPTION

Upon completing construction of all Bayside Units and retiring all coal-fired Gannon units, the H. L. Culbreath Bayside Power Station will have an electrical production capacity of 2845 MW based on the following nominal capacities: Bayside Unit 1 (746 MW), Bayside Unit 2 (1090 MW), Bayside Unit 3 (501 MW), and Bayside Unit 4 (508 MW). Note that the final design may not fully utilize the nameplate capacities of the existing steam-electrical turbines. The following table summarizes the emission units regulated by this air construction permit.

EU No.	Status	Emission Unit Description
001 [a]	Retired	Gannon Unit 1 – coal fired boiler (125 MW steam electrical generator)
002 [a]	Retired	Gannon Unit 2 – coal fired boiler (125 MW steam electrical generator)
003 [a]	Retired	Gannon Unit 3 – coal fired boiler (163 MW steam electrical generator)
004 [a]	Retired	Gannon Unit 4 – coal fired boiler (170 MW steam electrical generator)
005 [a]	Retired	Gannon Unit 5 – coal fired boiler (239 MW steam electrical generator)
006 [a]	Retired	Gannon Unit 6 – coal fired boiler (414 MW steam electrical generator)
008 [a]	Functional	Gannon Coal Yard
020 [b]	Operating	Bayside Unit 1A – 169 MW combined cycle gas turbine
021 [b]	Operating	Bayside Unit 1B – 169 MW combined cycle gas turbine
022 [b]	Operating	Bayside Unit 1C – 169 MW combined cycle gas turbine
023 [c]	Operating	Bayside Unit 2A – 169 MW combined cycle gas turbine
024 [c]	Operating	Bayside Unit 2B – 169 MW combined cycle gas turbine
025 [c]	Operating	Bayside Unit 2C – 169 MW combined cycle gas turbine
026 [c]	Operating	Bayside Unit 2D – 169 MW combined cycle gas turbine
027 [d]	Proposed	Bayside Unit 3A – 169 MW combined cycle gas turbine
028 [d]	Proposed	Bayside Unit 3B – 169 MW combined cycle gas turbine
029 [e]	Proposed	Bayside Unit 4A – 169 MW combined cycle gas turbine
030 [e]	Proposed	Bayside Unit 4B – 169 MW combined cycle gas turbine

Notes

a. The coal fired Gannon boilers were permanently retired on the following dates: Unit 1 (04/16/03); Unit 2 (04/15/03); Unit 3 (11/01/03); Unit 4 (10/12/03); Unit 5 (01/30/03); and Unit 6 (09/30/03). The Gannon coal yard (EU 008) remains functional.

b. Bayside Unit 1 is constructed and began commercial operation on March 16, 2003. The three gas turbines comprising Bayside Unit 1 re-power the 239 MW steam electrical generator from Gannon Unit 5.

c. Bayside Unit 2 is constructed and began commercial operation on November 19, 2003. The four gas turbines comprising Bayside Unit 2 re-power the 414 MW steam electrical generator from Gannon Unit 6.

d. The two gas turbines comprising Bayside Unit 3 will re-power the 163 MW steam electrical generator from Gannon Unit 3. This revised permit authorizes a phase of simple cycle operation for these units.

e. The two gas turbines comprising Bayside Unit 4 will re-power the 170 MW steam electrical generator from Gannon Unit 4.

REGULATORY CLASSIFICATION

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

Title IV: All Bayside gas turbines are subject to the Phase II Acid Rain requirements. All Gannon boilers have been permanently shutdown and are considered "retired units" in accordance with the Acid Rain provisions.

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

Site Certification: The facility is not subject to any specific power plant site certification requirements.

PSD: The facility is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

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

NESHAP: The re-powered facility is not a major source of hazardous air pollutants; therefore the National Emissions Standards for Hazardous Air Pollutants in Subpart YYYY of 40 CFR 63 do not apply to the gas turbines.

RELEVANT DOCUMENTS

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

- DEP/TECO Consent Final Judgment signed on December 7, 1999.
- EPA/TECO Consent Decree entered on October 5, 2000.
- Original Permit No. PSD-FL-301 issued on March 30, 2001 including the application and related correspondence. This permit (Project No. 0570040-013-AC) authorized construction of Bayside Units 1 and 2.
- Revised Permit No. PSD-FL-301A issued on January 8, 2002 including the application and related correspondence. This permit (Project No. 0570040-015-AC) included the construction of Bayside Units 3 and 4.
- Revised Permit No. PSD-FL-301B issued on November 9, 2004 including the application and related correspondence. This permit (Project No. 0570040-021-AC) revised Condition 17 related to monitoring data exclusions.
- Application No. 0570040-019-AC (PSD-FL-301C) received on July 22, 2003 and related correspondence to make it complete.

APPENDICES

The following Appendices are attached as part of this permit.

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

ADMINISTRATIVE REQUIREMENTS

1. Effective Date: The effective date of this permit is specified on the placard page (page 1).

2. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit shall 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. Copies shall also be provided to each Compliance Authority.

3. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications shall be submitted to the Air Management Division of the Environmental Protection Commission of Hillsborough County at 1410 North 21 Street, Tampa, FL 33605. Copies of all such documents shall 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.

4. 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.

5. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. [Rule 62-4.160, F.A.C.]

6. 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.]

7. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months of the effective date of this permit, 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/TECO Consent Final Judgment or the EPA/TECO Consent Decree. [40 CFR 52.21(r)(2)]

8. 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/TECO Consent Final Judgment or the EPA/TECO Consent Decree. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C.]

9. 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 will 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 51.166(j)(4)]

10. 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.]

11. 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 62-210.200 (Definitions) and 62-210.300(1), F.A.C.]

12. 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]

13. 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 with copies to the 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 the 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.; 40 CFR 60.7; 40 CFR 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 Compliance Authority, 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 Compliance Authority. [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 Compliance Authority 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 the 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 Compliance Authority 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.]

This section of the permit addresses the following emissions units.

Emissions Units 020 – 026: Bayside Units 1 and 2

Description: Each emissions unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack 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 exclusive fuel.

Heat Input: At a compressor inlet air temperature of 59° F and firing 1842 MMBtu (HHV) per hour of natural gas, each unit produces a nominal 169 MW of shaft-driven electricity. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,000 acfm at 220° F.

Generating Capacity: The following table summarizes the electrical generating capacity for each combination of combined cycle gas turbines and steam-electrical turbines.

EU No.	Bayside GT Unit	GT MW, Shaft	Existing Gannon ST	MW, ST	Total
020	1A	169 MW	No. 5	239	746
021	1B	169 MW			
022	1C	169 MW			
023	2A	169 MW	No. 6	414	1090
024	2B	169 MW			
025	2C	169 MW			
026	2D	169 MW			
Totals	7 GTs	1183 MW	2 STs	653	1836

Note: GT means gas turbine. The nameplate generating capacity is shown for the steam-electrical turbines (ST). The final design may not fully utilize the nameplate generating capacity.

Controls: The efficient combustion of natural gas at high temperatures minimizes the emissions of CO, PM/PM_{10}, and VOC. Firing natural gas as the only authorized fuel minimizes emissions of SAM and SO_2 because natural gas contains only small amounts of sulfur. A selective catalytic reduction (SCR) system combined with dry low-NOx (DLN) combustion technology reduces NOx emissions.

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

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. 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

3. Construction: Bayside Unit 1 is constructed and began commercial operation on March 16, 2003. Bayside Unit 2 is constructed and began commercial operation on November 19, 2003. The revised permit (PSD-FL-301C) does not authorize any additional construction for these units. [Application; Rule 62-212.400(BACT), F.A.C.]

4. 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 169 MW of shaft-driven 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]

5. Heat Recovery Steam Generators (HRSG): Each gas turbine system includes an unfired HRSG with three levels of steam conditions (high pressure, intermediate pressure, and low pressure). [Design]

6. Automated Control System: The permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ Mark VI automated control system (or better) for each gas turbine. 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 and shutdown. [Design; 62-212.400(BACT), F.A.C.]

7. DLN Combustion Technology: The permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to provide efficient lean premix combustion. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Design; Rule 62-212.400(BACT), F.A.C.]

8. SCR System: The permittee shall install, tune, operate and maintain a selective catalytic reduction (SCR) system to reduce NOx emissions from each combined cycle gas turbine. The SCR system shall consist of an ammonia injection grid, catalyst, ammonia storage, a monitoring and control system, electrical system, piping, and other ancillary equipment. The SCR system shall be designed to reduce NOx emissions while minimizing ammonia slip within the permitted levels. [DEP/TECO Consent Final Judgment; EPA/TECO Consent Decree; Rule 62-4.070(3), F.A.C.]

9. Evaporative Inlet Air-Cooling System: Each gas turbine system includes 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 increases power production with additional fuel combustion. *{Permitting Note: The installed equipment includes 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.}* [Applicant Request; Design]

PERFORMANCE RESTRICTIONS

10. Permitted Capacity: The maximum heat input rate to each gas turbine shall not exceed 1842 MMBtu per hour while producing approximately 169 MW (shaft). The maximum heat input rate is based on a

compressor inlet air temperature of 59° F, the higher heating value (HHV) of natural gas and expected performance levels. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

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

12. Restricted Operation: The hours of operation for each gas turbine are not limited (8760 hours per year). [Application; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

13. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods to minimize emissions during startup and shutdown. [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.}

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

    a. **Ammonia Slip**: Subject to the requirements of Condition 22 in this subsection, each SCR system shall be designed and operated for an ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. [Rule 62-4.070(3), F.A.C.]

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

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

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

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

f. **Visible Emissions**: Visible emissions shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. Except as allowed by Condition 17 of this subsection, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]

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

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

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

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

    Each 24-hour block average shall start at midnight each operating day and shall be calculated from 24 consecutive 1-hour averages. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of the available valid 1-hour averages. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

STARTUP, SHUTDOWN, MALFUNCTION, AND LOW LOAD OPERATION

16. <u>Excess Emissions Prohibited</u>: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in the compliance averages determined from the CO and NOx CEMS data. [Rule 62-210.700(4), F.A.C.]

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

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

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

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

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

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

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

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

(5) *DLN Tuning*: "DLN Tuning" means operating the gas turbine at intermittent loads throughout the full load range in order to adjust and tune the dry low-NOx (DLN) combustion system. DLN

tuning shall be conducted in accordance with manufacturer' recommendations. Emissions data collected during DLN tuning may be excluded from the 24-hour block compliance averages. *{Permitting Note: For example, a major tuning session would occur after combustor change-out.}*

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

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

To the extent practicable, the permittee shall minimize the amount and duration of emissions during periods of startup, shutdown, malfunction, DLN tuning, compressor blade drying, and over speed trip testing. If a CEMS reports emissions in excess of an emissions standard (24-hour block), the permittee shall notify the Compliance Authority within one working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Compliance Authority may request a written summary report of the incident. All emissions data allowed for exclusion shall be summarized in the Semiannual CEMS Report required in Condition 25 of this subsection.

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

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

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

EMISSIONS PERFORMANCE TESTING

18. Operating Rate During Testing: Emissions performance testing shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

19. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

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

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

20. Initial Compliance Tests: Each gas turbine shall be tested to demonstrate compliance with the emission standards for CO, NOx, visible emissions and ammonia slip. The tests shall 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 gas turbine. Tests for CO and NOx shall be conducted concurrently. Certified CEMS data may be used to demonstrate compliance with the initial CO and NOx standards. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.335]

21. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for ammonia slip and visible emissions. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. *{Permitting Note: Continuous compliance with the CO and NOx standards will be demonstrated with certified CEMS data.}* [Rules 62-212.400(BACT) and 62-297.310(7)(a)4, F.A.C.]

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

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

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

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

    Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

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

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

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

    c. **Data Exclusion**. CO, CO_2, and NOx emissions data shall be recorded by the CEMS at all times including episodes of startup, shutdown, malfunction, and tuning. CO and NOx emissions data recorded during such episodes may be excluded from the 24-hour block compliance averages in accordance with the requirements of Condition 17 of this subsection. All periods of data excluded due to startup, shutdown or malfunction shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited. Excluded emissions shall be summarized in the required semiannual report.

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

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

f. **Monitor Availability**. Monitor availability shall not be less than 95% in any calendar quarter. The report required in Condition 23e above shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Compliance Authority with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

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

[Rules 62-4.070(3), 62-210.700(5), and 62-212.400(BACT), F.A.C.]

24. <u>Ammonia Monitoring Requirements</u>: The permittee shall install, calibrate, maintain and operate, in accordance with the manufacturer's specifications, an ammonia flow meter to measure and record the ammonia injection rate through each SCR system. The permittee shall document the general range of ammonia flow rates required to meet emissions limitations over the range of gas turbine load conditions allowed in this permit by comparing NOx emissions recorded by the NOx monitor with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the gas turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

25. Semiannual CEMS Report: In addition to the reports required pursuant to 40 CFR 60.7, the permittee shall submit semiannual reports for each gas turbine summarizing the CEMS data and equipment. For each calendar quarter, the report shall include: the 24-hour block compliance averages for each day of operation; the number of 1-hour emission averages excluded from each 24-hour compliance average; the emissions rate of the excluded monitoring data; the reason for excluding monitoring data; the hours of missing data due to monitor downtime; the reason for any monitor downtime; unusual maintenance or repair of the CEMS; and a summary of any RATA tests performed. Based on operational data, the permittee shall also update the general range of ammonia flow rates required to meet NOx emissions limitations over the range of gas turbine load conditions. A report covering operations from January through June shall be submitted by July 30th of each year. A report covering operations from July through December shall be submitted by January 30th of each year. The report due dates may be modified by the Title V permit. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

26. Monitoring of Operations: To demonstrate compliance with the gas turbine capacity requirements, the permittee shall monitor and record the operating rate of each gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEMS required above, or by monitoring daily rates of consumption and heat content of natural gas in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

B. GANNON UNITS

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

EU ID	Status	Emission Unit Description
001	Retired	Gannon Unit 1 – coal fired boiler (125 MW steam electrical generator)
002	Retired	Gannon Unit 2 – coal fired boiler (125 MW steam electrical generator)
003	Retired	Gannon Unit 3 – coal fired boiler (163 MW steam electrical generator)
004	Retired	Gannon Unit 4 – coal fired boiler (170 MW steam electrical generator)
005	Retired	Gannon Unit 5 – coal fired boiler (239 MW steam electrical generator)
006	Retired	Gannon Unit 6 – coal fired boiler (414 MW steam electrical generator)
008	Functional	Gannon Coal Yard

SHUTDOWN REQUIREMENTS

1. Shutdown of Coal-Fired Gannon Units: Pursuant to this federally enforceable PSD air construction permit, the coal-fired boilers for Gannon Units 1 through 6 (EUs 001 – 006) shall be permanently shut down no later than December 31, 2004. Based on the "Retired Unit Exemption" form submitted to the Department, all of these units have been permanently shut down and the dates of permanent retirement are: Unit 1 (04/16/03); Unit 2 (04/15/03); Unit 3 (11/01/03); Unit 4 (10/12/03); Unit 5 (01/30/03); and Unit 6 (09/30/03). [Permit No. PSD-FL-301, as revised; EPA/TECO Consent Decree; DEP Form No. 62-210.900(1)(a)3, F.A.C.]

2. Coal Yard: The Gannon coal yard (EU 008) remains operable. Coal throughput for this facility shall not exceed 2.85 million tons in any 12 consecutive months. *{Permitting Note: TECO is exploring possible long term plans to use the existing coal handling capabilities as a coal storage and distribution terminal. Additional permits may be required.}* [Rules 62-4.160(2), 62-210.200 (PTE), and 62-212.400(2)(a)2, F.A.C.; Permit No. 0570040-006-AC]

3. 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/TECO Consent Decree]

4. Revisions or Extensions: The provisions of this section shall not be extended or revised the without the prior approval of the U.S. EPA. [EPA/TECO Consent Decree]

C. BAYSIDE UNITS 3 AND 4

This section of the permit addresses the following emissions units.

Emissions Units 027 – 030: Bayside Units 3 and 4

Description: Each emissions unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a combined cycle exhaust stack (150 feet tall and 19.0 feet in diameter), a simple cycle exhaust stack for Units 3A and 3B (114 feet tall and 18.8 feet in diameter), and associated support equipment. Each unit fires natural gas and Units 3A and 3B may fire distillate oil as a restricted alternate fuel (simple cycle) or as an emergency backup fuel (combined cycle).

Permitted Capacity: At a compressor inlet air temperature of 59° F, the maximum heat input rate to each gas turbine is 1842 MMBtu (HHV) per hour of natural gas. At a compressor inlet air temperature of 59° F, the maximum heat input rate to each Unit 3A or 3B gas turbine is 2015 MMBtu (HHV) per hour of distillate oil.

Stack Conditions: When Units 3 and 4 are operating as combined cycle units at full load, exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,000 acfm at 220° F for gas firing and 1,160,000 acfm at 275° F for oil firing (Unit 3 only). When Units 3A or 3 B are operating as simple cycle units at full load, exhaust gases exit the stack with a volumetric flow rate of approximately 2,394,000 acfm at 1120° F for gas firing and 2,469,000 acfm at 1100° F for oil firing.

Generating Capacity: The following table summarizes the electrical generating capacity for each combination of combined cycle gas turbines and steam-electrical turbines.

EU No.	Bayside GT Unit	GT MW, Shaft	Existing Gannon ST	MW, ST	Total
027	3A	169 MW	No. 3	163	501
028	3B	169 MW			
029	4A	169 MW	No. 4	170	508
030	4B	169 MW			
Totals	4 GTs	676 MW	2 STs	333	1009

Note: GT means gas turbine. The nameplate generating capacity is shown for the steam-electrical turbines (ST). The final design may not fully utilize the nameplate generating capacity.

Controls: The efficient combustion of clean fuels minimizes the emissions of CO, PM/PM_{10}, and VOC. The firing of very low sulfur fuels minimizes potential emissions of SAM and SO_2. Dry low-NOx (DLN) combustion technology when firing natural gas and water injection when firing distillate oil inhibit NOx emissions. When operating in the combined cycle mode, a selective catalytic reduction (SCR) system further reduces NOx emissions.

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

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. NSPS Requirements: Each gas turbine shall comply with Subpart GG in 40 CFR 60, the New Source Performance Standards (NSPS) for Stationary Gas Turbines, as specified in Appendix GG of this permit. In addition, each gas turbine shall comply with the applicable requirements of Subpart A in 40 CFR 60, the

NSPS 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). [40 CFR 60; Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT

3. Construction: Bayside Unit 3 is scheduled to commence construction in May of 2005 and complete construction in 2006. Units 3A and 3B may be installed and operated as simple cycle units and later converted to combined cycle units. Unit 4 will be added as a combined cycle unit. The permittee shall inform the Department and Compliance Authority of any substantial changes to the construction schedule including conversion of Units 3A and 3B to combined cycle operation. Pursuant to 40 CFR 52.21(r)(2):
   a. Construction of Bayside Units 3A and 3B shall commence within 18 months after permit issuance. Otherwise, authorization to construct shall become invalid.
   b. Conversion of Units 3A and 3B to combined cycle operation shall be complete before this permit expires.
   c. Construction of combined cycle Unit 4 shall be complete before this permit expires.
   d. Each combined cycle unit shall include an SCR system to reduce NOx emissions.
   e. For good cause, the permittee may request that this PSD air construction permit be extended. When processing any request for a permit extension, the Department may require revalidation of the BACT determinations or a revised netting analysis or both.

   [Application; Rule 62-212.400(BACT), F.A.C.]
4. Gas Turbines: The permittee is authorized to install, tune, operate and maintain four new General Electric Model PG7241(FA) gas turbines with electrical generator sets, each designed to produce a nominal 169 MW of shaft-driven electrical power. Each unit shall be designed for eventual operation 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 combined cycle exhaust stack (150 feet tall and 19.0 feet in diameter), and associated support equipment. Bayside Units 3A and 3B may be installed as simple cycle units and later converted to combined cycle units. Units 3A and 3B will each have a simple cycle exhaust (114 feet tall and 18.8 feet in diameter). [Applicant Request; Design]
5. Heat Recovery Steam Generators (HRSG): Each gas turbine system shall be designed to include an unfired HRSG with three levels of steam conditions (high pressure, intermediate pressure, and low pressure). [Design]
6. Automated Control System: The permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ Mark VI automated control system (or better) for each gas turbine. 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 and shutdown. [Design; 62-212.400(BACT), F.A.C.]
7. Combustion Controls
   a. *DLN Combustion Technology*: Each gas turbine shall incorporate the General Electric dry low-NOx combustion system (DLN 2.6 or better) to provide efficient lean premix combustion. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations to maintain CO and

NOx emissions at the optimum levels. [Design; Rule 62-212.400(BACT), F.A.C.]

b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system on Units 3A and 3B to reduce NOx emissions from each gas turbine when firing distillate oil. The water injection system shall be tuned to achieve the permitted levels for CO and NOx emissions during simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to achieve the NOx emission standard for oil firing during simple cycle operation on a 1-hour basis. [Design; Rule 62-212.400(BACT), F.A.C.]

8. SCR System: The permittee shall install, tune, operate and maintain a selective catalytic reduction (SCR) system to reduce NOx emissions from each combined cycle gas turbine. The SCR system shall consist of an ammonia injection grid, catalyst, ammonia storage, a monitoring and control system, electrical system, piping, and other ancillary equipment. The SCR system shall be designed to reduce NOx emissions while minimizing ammonia slip within the permitted levels for gas firing. [DEP/TECO Consent Final Judgment; EPA/TECO Consent Decree; Rule 62-4.070(3), F.A.C.]

9. Evaporative Inlet Air-Cooling System: Each gas turbine system includes 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 increases power production with additional fuel combustion. *{Permitting Note: The proposed equipment includes 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.}* [Applicant Request; Design]

PERFORMANCE RESTRICTIONS

10. Permitted Capacity: At a compressor inlet air temperature of 59° F, the maximum heat input rate to each gas turbine is 1842 MMBtu (HHV) per hour of natural gas. At a compressor inlet air temperature of 59° F, the maximum heat input rate to each Unit 3A and 3B gas turbine is 2015 MMBtu (HHV) per hour of distillate oil. The maximum heat input rates are based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel and the expected performance levels. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

11. Allowable Fuels: The gas turbines shall fire only the following fuels.

a. *Natural Gas*: Each gas turbine shall fire pipeline natural gas with a fuel sulfur content of no more than 2 grains per 100 SCF of natural gas based on a 12-month rolling average. Compliance shall be demonstrated each month by compiling the daily fuel sulfur analyses provided by the pipeline vendor. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods. [Design; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.; DEP/TECO Consent Final Judgment; EPA/TECO Consent Decree]

b. *Distillate Oil – Units 3A and 3B*: As a restricted alternate fuel, Units 3A and 3B may fire new No. 2 distillate oil with a maximum fuel sulfur content of no more than 0.05% sulfur by weight. During simple cycle operation, each gas turbine shall fire no more than 9,722,300 gallons of distillate oil during any consecutive 12-month period (equivalent to 700 full load equivalent hours of operation). Initial compliance with the fuel 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. [Design; Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

c. *Distillate Oil – Units 3A and 3B, Combined Cycle Operation Only*: Once converted to combined cycle operation, Units 3A and 3B may be fired with new No. 2 fuel oil if and only if:

(1) The Unit cannot be fired with natural gas;

(2) The Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil;

(3) The oil to be used in firing the Unit has a sulphur content of less than 0.05 percent (by weight);

(4) Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and

(5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

[EPA/TECO Consent Decree]

12. <u>Hours of Operation</u>: The hours of operation for each gas turbine are not limited (8760 hours per year). [Application; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

13. <u>Operating Procedures</u>: The Best Available Control Technology (BACT) determinations for CO, PM/PM_{10}, and VOC emissions established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods to minimize emissions during startup and shutdown. [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.}

14. <u>Emissions Standards - Performance Tests</u>: The gas turbines shall not exceed the following standards as determined by the emissions performance tests conducted at permitted capacity.

Pollutant	Emission Standards – Performance Tests	Test Method
Simple Cycle Operation – Units 3A and 3B Only		
Carbon Monoxide (CO)	≤ 28.7 pounds per hour and 7.8 ppmvd corrected to 15% oxygen (gas) ≤ 40.5 pounds per hour and 9.0 ppmvd corrected to 15% oxygen (oil)	EPA Method 10 3 test runs
Nitrogen Oxides (NOx)	≤ 69.1 pounds per hour and 10.5 ppmvd corrected to 15% oxygen (gas) ≤ 320.3 pounds per hour and 42.0 ppmvd corrected to 15% oxygen (oil)	EPA Method 7E 3 test runs
Visible Emissions	≤ 10% opacity, 6-minute block average (gas/oil)	EPA Method 9 30 minutes

Pollutant	Emission Standards – Performance Tests	Test Method
Combined Cycle Operation – Units 3 and 4		
Ammonia Slip	Subject to the requirements of Condition 22 in this subsection, each SCR system shall be designed and operated for an ammonia slip target of less than 5 ppmvd corrected to 15% oxygen for gas firing.	CTM-027 3 test runs
Carbon Monoxide (CO)	≤ 28.7 pounds per hour and 7.8 ppmvd corrected to 15% oxygen (gas)	EPA Method 10 3 test runs
Nitrogen Oxides (NOx)	≤ 23.1 pounds per hour and 3.5 ppmvd corrected to 15% oxygen (gas)	EPA Method 7E 3 test runs
Visible Emissions	≤ 10% opacity, 6minute block average (gas/oil)	EPA Method 9 30 minutes

a. The mass emission limits are based on full load and a compressor inlet temperature of 59° F.

b. NOx emissions are defined as oxides of nitrogen reported as NO_2.

c. Operating data shall be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

d. The CO and NOx standards represent the initial standards for "new and clean" units. Subsequent compliance shall be demonstrated with data collected by the certified CEMS.

e. The efficient combustion of clean fuels represents the Best Available Control Technology (BACT) requirements for emissions of particulate matter and volatile organic compounds. Compliance with carbon monoxide and visible emissions standards shall serve as continuous indicators of efficient combustion to minimize emissions of these pollutants. Compliance with the fuel sulfur specifications of this permit minimizes potential emissions of sulfuric acid mist and sulfur dioxide. No performance tests are required for these pollutants.

f. Only the CEMS-based CO and NOx emissions standards apply to Units 3A and 3B when firing distillate oil and operating in combined cycle mode because these units can only fire distillate oil as an "emergency backup fuel" when operating in this mode.

[Rules 62-4.070(3), 62-212.400(BACT), and 62-297.310, F.A.C.; DEP/TECO Consent Final Judgment; EPA/TECO Consent Decree; 40 CFR 60.332]

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

Pollutant	CEMS-Based Emission Standards	Method
Simple Cycle Operation – Units 3A and 3B Only		
Carbon Monoxide (CO)	≤ 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average (gas/oil)	CO CEMS
Nitrogen Oxides (NOx)	≤ 10.5 ppmvd corrected to 15% oxygen based on a 24-hour block average (gas) ≤ 42.0 ppmvd corrected to 15% oxygen based on a 24-hour block average (oil)	NOx CEMS
Combined Cycle Operation – Units 3 and 4		
Carbon Monoxide (CO)	≤ 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average (gas/oil)	CO CEMS
Nitrogen Oxides (NOx)	≤ 3.5 ppmvd corrected to 15% oxygen based on a 24-hour block average (gas) ≤ 12.0 ppmvd corrected to 15% oxygen based on a 24-hour block average (oil)	NOx CEMS

Each 24-hour block average shall start at midnight each operating day and shall be calculated from 24 consecutive 1-hour averages. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of the available valid 1-hour averages. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

STARTUP, SHUTDOWN, MALFUNCTION, AND LOW LOAD OPERATION

16. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in the compliance averages determined from the CO and NOx CEMS data. [Rule 62-210.700(4), F.A.C.]

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

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

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

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

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

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

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

startup and standard startups, shutdowns and/or malfunctions within the same 24 hour period, a total of sixteen 1-hour CEMS emissions averages may be excluded with no more than four of those sixteen 1-hour CEMS emissions averages being excluded due to standard startups, shutdowns, and malfunctions (total). This condition applies only to the gas turbine being used for the cold steam turbine startup. The permittee shall notify the Compliance Authority no later than 24 hours after beginning a cold steam turbine startup. Notification may be by phone, facsimile, email, or letter.

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

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

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

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

To the extent practicable, the permittee shall minimize the amount and duration of emissions during periods of startup, shutdown, malfunction, DLN tuning, compressor blade drying, and over speed trip testing. If a CEMS reports emissions in excess of an emissions standard (24-hour block), the permittee shall notify the Compliance Authority within one working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Compliance Authority may request a written summary report of the incident. All emissions data allowed for exclusion shall be summarized in the Semiannual CEMS Report required in Condition 25 of this subsection.

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

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

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

EMISSIONS PERFORMANCE TESTING

18. Operating Rate During Testing: Emissions performance testing shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

19. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

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

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

20. Initial Compliance Tests: To demonstrate initial compliance with the emissions standards, tests shall be conducted on each gas turbine within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each gas turbine. Tests shall be conducted in accordance with the following requirements.

    a. *Simple Cycle Units 3A and 3B*: Each simple cycle gas turbine shall be tested to demonstrate initial compliance with the emissions standards for CO, NOx, and visible emissions in Condition 14 of this subsection when firing natural gas and distillate oil.

    b. *Combined Cycle Units 3 and 4*: Each combined cycle gas turbine shall be tested to demonstrate compliance with the emissions standards for CO, NOx, visible emissions and ammonia slip in Condition 14 of this subsection when firing natural gas. *{Permitting Note: For combined cycle operation of Units 3A and 3B, initial tests when firing distillate oil are not required because this fuel may only be fired as a restricted emergency backup fuel.}*

    Tests for CO and NOx shall be conducted concurrently. Certified CEMS data may be used to demonstrate initial compliance with the CO and NOx emissions standards. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.335]

21. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine is subject to the following testing requirements.

    a. *Simple Cycle Units 3A and 3B*: Each simple cycle gas turbine shall be tested annually to demonstrate compliance with the standard for visible emissions in Condition 14 of this subsection when firing natural gas and when firing distillate oil (if the unit fires distillate oil for more than 400 hours during the federal fiscal year).

    b. *Combined Cycle Units 3 and 4*: Each combined cycle gas turbine shall be tested to demonstrate compliance with the standards for visible emissions and ammonia slip in Condition 14 of this subsection when firing natural gas. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. Units 3A and 3B shall also be tested for visible emissions if the unit fires distillate oil for more than 400 hours during the federal fiscal year.

    {Permitting Note: Continuous compliance with the CO and NOx standards will be demonstrated by data collected from the certified CEMS.} [Rules 62-212.400(BACT) and 62-297.310(7)(a)3 and 4, F.A.C.]

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

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

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

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

    Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

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

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

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

    c. **Data Exclusion**. CO, CO_2, and NOx emissions data shall be recorded by the CEMS at all times including episodes of startup, shutdown, malfunction, and tuning. CO and NOx emissions data recorded during such episodes may be excluded from the 24-hour block compliance averages in accordance with the requirements of Condition 17 of this subsection. All periods of data excluded due to startup, shutdown or malfunction shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited. Excluded emissions shall be summarized in the required semiannual report.

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

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

f. **Monitor Availability.** Monitor availability shall not be less than 95% in any calendar quarter. The report required in Condition 23e above shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Compliance Authority with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

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

[Rules 62-4.070(3), 62-210.700(5), and 62-212.400(BACT), F.A.C.]

24. Ammonia Monitoring Requirements: The permittee shall install, calibrate, maintain and operate in accordance with the manufacturer's specifications an ammonia flow meter to measure and record the ammonia injection rate through each SCR system. The permittee shall document the general range of ammonia flow rates required to meet emissions limitations over the range of gas turbine load conditions allowed in this permit by comparing NOx emissions recorded by the NOx monitor with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the gas turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

25. Semiannual CEMS Report: In addition to the reports required pursuant to 40 CFR 60.7, the permittee shall submit semiannual reports for each gas turbine summarizing the CEMS data and equipment. For each calendar quarter, the report shall include: the 24-hour block compliance averages for each day of operation; the number of 1-hour emission averages excluded from each 24-hour compliance average; the emissions rate of the excluded monitoring data; the reason for excluding monitoring data; the hours of missing data due to monitor downtime; the reason for any monitor downtime; unusual maintenance or repair of the

CEMS; and a summary of any RATA tests performed. Based on operational data, the permittee shall also update the general range of ammonia flow rates required to meet NOx emissions limitations over the range of gas turbine load conditions. A report covering operations from January through June shall be submitted by July 30th of each year. A report covering operations from July through December shall be submitted by January 30th of each year. The report due dates may be modified by the Title V permit. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

26. Monitoring of Operations: To demonstrate compliance with the gas turbine capacity requirements, the permittee shall monitor and record the operating rate of each gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEMS required above, or by monitoring daily rates of consumption and heat content of natural gas in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

CEMS	-	Continuous Emissions Monitoring System
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

SUMMARY OF BACT DETERMINATIONS AND EMISSIONS STANDARDS

Background Discussion

The Tampa Electric Company operates the H. L. Culbreath Bayside Power Station in Tampa (Hillsborough County), an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. The electrical power plant was formerly known as the F. J. Gannon Station, but was re-powered with combined cycle gas turbines firing natural gas. The actual and potential annual emissions of several pollutants from the existing facility are greater than the PSD applicability thresholds defined in Rule 62-212.400, F.A.C. Therefore, the plant is an existing PSD-major facility and new projects are subject to review for PSD applicability.

In accordance with the DEP/TECO Consent Final Judgment and the EPA/TECO Consent Decree (Settlement Agreements), TECO was required to re-power the coal fired boilers at the F.J. Gannon Plant with natural gas fired units meeting a NOx standard of 3.5 ppmvd. Shut down of the coal fired boilers created emissions decreases that could be used in a PSD netting analysis. However, TECO could not take advantage of the full emissions decreases because the re-powering project was the result of alleged violations of the new source preconstruction review regulations. Therefore, emissions decreases from the shutdown Gannon Units must be adjusted downward to represent BACT-level controls on the coal-fired units.

Bayside Units 1 and 2, Permit No. PSD-FL-301 (Project No. 0570040-013-AC)

The project proposed the following: construction of Bayside Unit 1 consisting of a 3-on-1 combined cycle gas turbine system to re-power Gannon Unit 5; and construction of Bayside Unit 2 consisting of a 4-on-1 combined cycle gas turbine system to re-power Gannon Unit 6. Based on the PSD netting analysis, this project required determinations of the Best Available Control Technology (BACT) for emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). The project netted out of PSD review for nitrogen oxides (NOx) and sulfur dioxide (SO_2) emissions. However, in accordance with the Settlement Agreements, each gas turbine is required to fire natural gas as the primary fuel and achieve a NOx standard of no more than 3.5 ppmvd. Therefore, Bayside Units 1 and 2 were permitted to fire natural gas as the primary fuel and required to install selective catalytic reduction (SCR) systems to reduce NOx emissions. Distillate oil was allowed only as a restricted emergency backup fuel in accordance with the EPA/TECO Consent Decree. The permit required the installation of continuous emissions monitoring systems (CEMS) to determine compliance with the CO and NOx emissions standards. See the Technical Evaluation and Preliminary Determination for a full discussion of the PSD netting analysis and BACT determinations.

Bayside Units 3 and 4, Permit No. PSD-FL-301A (Project No. 0570040-015-AC)

In addition to the previously permitted Bayside Units 1 and 2, the project proposed the following: construction of Bayside Unit 3 consisting of a 2-on-1 combined cycle gas turbine system to re-power Gannon Unit 3; and construction of Bayside Unit 4 consisting of a 2-on-1 combined cycle gas turbine system to re-power Gannon Unit 4. Natural gas was requested and specified as the exclusive fuel. Based on the netting analysis, this project netted out of PSD review for NOx and SO_2 emissions. BACT determinations for CO, PM/PM_{10}, and VOC emissions were made for Bayside Units 3 and 4 and revalidated for Bayside Units 1 and 2.

Bayside Units 1 – 4, Permit No. PSD-FL-301B (Project No. 0570040-021-AC)

The project was a permit revision related to monitoring data exclusions in Condition 17. No BACT determinations were required.

Bayside Units 3 and 4, Permit No. PSD-FL-301C (Project No. 0570040-019-AC)

Bayside Units 1 and 2 have been constructed and are in operation. Bayside Units 3 and 4 have not yet been constructed. The project proposed the following: initial construction of Bayside Unit 3A and 3B as simple cycle gas turbines; distillate oil firing for Units 3A and 3B during simple cycle operation (restricted to 700 full load equivalent hours); after an initial phase of simple cycle operation, future conversion of Bayside Units 3A and 3B to combined cycle operation; future construction of Bayside Unit 4 as a combined cycle unit. Based on the netting analysis, this project also netted out of PSD review for NOx and SO_2 emissions. Bayside Units 1 and 2 are in operation and the previous BACT determinations for these units remain unchanged by this permitting action. Bayside Units 3 and 4 have not been constructed and new (re-validated) BACT determinations were made for CO, PM/PM_{10}, and VOC emissions.

Emissions Standards Summaries

The following tables summarize the Department's current BACT determinations and emissions standards.

Table B-1. BACT Emissions Standards for Bayside Units 1 – 4 [a]

Pollutant	Controls [c] and Standards [g]
Fuel Specifications [b]	*Gas Standard*: Pipeline natural gas (≤ 2 grains per 100 SCF, 12 month rolling average) *Oil Standard*: Distillate oil (≤ 0.05% sulfur by weight)
All Modes of Operation - - Compliance Tests [d]	
CO	*Control*: Efficient combustion of clean fuels *Gas Standard*: 7.8 ppmvd @ 15% O_2 (28.7 lb/hour) *Oil Standard*: 9.0 ppmvd @ 15% O_2 (40.5 lb/hour)
PM/PM_{10}	*Controls*: Efficient combustion of clean fuels *Standard*: 10% opacity, 6-minute block average (gas/oil) *Comments*: The CO CEMS serves as a continuous indicator of efficient combustion.
VOC	*Controls*: Efficient combustion of clean fuels *Comments*: The CO CEMS serves as a continuous indicator of efficient combustion.
All Modes of Operation - CEMS Data [e]	
CO (BACT)	*Control*: Efficient combustion of clean fuels *Standard*: 9.0 ppmvd @ 15% O_2, 24-hour block average (gas/oil)

Table B-2. Other Emissions Standards for Bayside Units 1 – 4 [a]

Pollutant	Controls [c] and Standards [g]
Combined Cycle Operation - Compliance Tests [d, h]	
Ammonia	*Standard*: 5 ppmvd @ 15% O_2, combined cycle operation with SCR [f]
NOx	*Controls*: SCR with DLN combustion (gas) *Standard*: 3.5 ppmvd @ 15% O_2 (23.1 lb/hour)
Combined Cycle Operation - CEMS Data [c]	
NOx	*Controls*: SCR plus DLN combustion technology (gas) and wet injection (oil) *Gas Standard*: 3.5 ppmvd @ 15% O_2, 24-hour block average *Oil Standard*: 12.0 ppmvd @ 15% O_2, 24-hour block average
Simple Cycle Operation - Compliance Tests [d]	
NOx	*Controls*: DLN combustion technology (gas) and wet injection (oil) *Gas Standard*: 10.5 ppmvd @ 15% O_2 (69.1 lb/hour) *Oil Standard*: 42.0 ppmvd @ 15% O_2 (320.3 lb/hour)
Simple Cycle Operation - CEMS Data [e]	
NOx	*Controls*: DLN combustion technology (gas) and wet injection (oil) *Gas Standard*: 10.5 ppmvd @ 15% O_2, 24-hour block average *Oil Standard*: 42.0 ppmvd @ 15% O_2, 24-hour block average

Notes:

a. Each gas turbine is a General Electric Model PG7241(FA).

b. Potential SAM and SO_2 emissions are limited by the fuel specifications.

c. "SCR" means selective catalytic reduction system. "DLN" means dry low-NOx combustion technology.

d. Mass emissions rates are based on operation at permitted capacity and a compressor inlet temperature of 59° F.

e. "CEMS" means continuous emissions monitoring system.

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

g. Only Units 3A and 3B are authorized to fire distillate oil. During simple cycle operation of Units 3A and 3B, distillate oil may be fired as a restricted alternate fuel limited to 9,722,300 gallons during any consecutive 12-month period (equivalent to 700 full load equivalent hours of operation). During combined cycle operation of Units 3A and 3B, distillate oil may only be fired as an emergency backup fuel subject to the requirements of the EPA-TECO Consent Decree.

h. Only Units 3A and 3B may fire distillate oil. These units will be installed initially as simple cycle units and later converted to combined cycle operation. Once converted, Units 3A and 3B may only fire distillate oil as an emergency backup fuel. Therefore, no initial NOx compliance test is required for oil firing.

SUMMARY OF MASS EMISSIONS RATES FOR FIRING GAS

Table E-1. Summary of Mass Emission Rates for Firing Natural Gas

Pollutant	Compressor Inlet Temperature	Mass Emission Rate lb/hour
CO	18° F	31.1
	35° F	30.0
	59° F	28.7
	72° F	27.8
	93° F	26.9
NOx	18° F	24.7
	35° F	23.8
	59° F	23.1
	72° F	22.6
	93° F	21.9
PM/PM_{10}	18° F	11.5
	35° F	11.4
	59° F	11.3
	72° F	11.3
	93° F	11.2
VOC	18° F	3.0
	35° F	3.0
	59° F	2.8
	72° F	2.7
	93° F	2.7

Notes:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (X);

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

(c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

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

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

(c) Records of monitoring information shall include:

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

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

NSPS SUBPART GG REQUIREMENTS

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

Pursuant to 40 CFR 60.332, Standard for Nitrogen Oxides:

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

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

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

Where:

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

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

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

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

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

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

Department requirement: For natural gas, the "F" value shall be assumed to be 0.

{Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" value provided by the applicant is approximately 10.0 for natural gas. The equivalent emission standard is 108 ppmvd @ 15% oxygen. The permit standards are more stringent than this requirement.}

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

Pursuant to 40 CFR 60.333, Standard for Sulfur Dioxide:

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

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

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

Pursuant to 40 CFR 60.334, Monitoring of Operations:

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

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

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

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

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

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

Department requirement: NOx CEMS data shall substitute for the above requirement because NOx monitoring is required to demonstrate compliance with the permit standards. NOx CEMS data shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

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

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

Pursuant to 40 CFR 60.335, Test Methods and Procedures:

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

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

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

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

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

Where:

NOx	=	emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent
NOxo	=	observed NOx concentration, ppm by volume
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg

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

Ho = observed humidity of ambient air, g H_2O/g air

e = transcendental constant, 2.718

Ta = ambient temperature, °K

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

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

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

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

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

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

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

{Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed in the permit pursuant to Department authority and is consistent with guidance from EPA Region 4.}

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

<u>Department requirement</u>: **The permit specifies sulfur monitoring methods.**

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

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

SEMIANNUAL CONTINUOUS MONITOR SYSTEMS REPORT

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

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

Reporting period dates: From ____________________ to ____________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ____

Date of Latest CMS Certification or Audit: ____________________

Process Units Description: ____

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

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

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

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

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

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

____
Name

____
Title

____ ____________________
Signature *Date*

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:

Mr. Wade A. Maye
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X B.R ☒ Agent ☐ Addressee

B. Received by (*Printed Name*) B. Rhind

C. Date of Delivery 3/14/02

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
(*Transfer from service label*) 7000 1670 0013 3109 9335

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

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

7000 1670 0013 3109 9335

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

Postmark Here

To
Ser
Stre
City

Mr. Wade A. Maye
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

PS Form 3800, May 2000 See Reverse for Instructions

TAMPA ELECTRIC

January 21, 2005

Mr. Jeffery F. Koerner, P.E.
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7928 2854 7029

Re: Tampa Electric Company
H.L. Culbreath Bayside Power Station
DRAFT PSD Units 3a&3b Air Permit
Public Notice of Intent
Permit No. PSD-FL-301C
Project No. 0570040-019-AC

Dear Mr. Koerner:

Please find enclosed the original Affidavit of Publication from the Tampa Tribune, as required by 62-110.106(5), F.A.C. This public notice was published in the legal section of the Tampa Tribune on Monday, January 17, 2005. If you have any questions, please feel free to telephone Greer Briggs or me at (813) 228-4302.

Sincerely,

Greer Briggs, for

Laura R. Crouch
Manager - Air Programs
Environmental, Health & Safety

EHS/bmr/GMB215

Enclosure

c/enc: Mr. Jerry Kissel, SWD Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak – NPS
Mr. Jerry Campbell, HEPC

Best Available Copy

THE TAMPA TRIBUNE

Published Daily

Tampa, Hillsborough County, Florida

State of Florida }
County of Hillsborough } ss.

Before the undersigned authority personally appeared C. Pugh, who on oath says that she is the Advertising Billing Supervisor of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of advertisement being a

LEGAL NOTICE

in the matter of PUBLIC NOTICE OF INTENT

was published in said newspaper in the issues of

JANUARY 17, 2005

Affiant further says that the said The Tampa Tribune is a newspaper published at Tampa in said Hillsborough County, Florida, and that the said newspaper has heretofore been continuously published in said Hillsborough County, Florida, each day and has been entered as second class mail matter at the post office in Tampa, in said Hillsborough County, Florida for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, this advertisement for publication in the said newspaper.

Sworn to and subscribed by me, this 19 day of JANUARY, A.D. 20 05

Personally Known ✓ or Produced Identification_____
Type of Identification Produced____________________

NOTARY SEAL
COMMISSION EXP.
2005

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection Project No. 0570040-019-AC / Draft Air Permit No. PSD-FL-301C TECO - H. L. Culbreath Bayside Power Station Hillsborough County, Florida

Applicant: The applicant for this project is the Tampa Electric Company (TECO). The applicant's authorized representative is Mr. Wade A. Maye, General Manager of the H. L. Culbreath Bayside Power Station. The applicant's mailing address is: H. L. Culbreath Bayside Power Station, Tampa Electric Company, P.O. Box 111, Tampa, Florida 33601-0111.

Facility Location: TECO operates the existing H. L. Culbreath Bayside Power Station (formerly the F. J. Gannon Station) in Tampa at 3602 Port Sutton Road in Hillsborough County, Florida.

Project: TECO is permitted to construct four combined cycle gas turbines systems (Bayside Units 1 - 4) to re-power the former F.J. Gannon Station. All six coal-fired Gannon boilers have been permanently shutdown. However, only Bayside Units 1 and 2 have been constructed and are in operation. The applicant proposes a revision of the current PSD air construction permit to add a phase of simple cycle operation and restricted distillate oil firing for the Bayside Unit 3A and 3B gas turbines. In addition, the project will extend the period of time to construct Bayside Units 3 and 4 as combined cycle gas turbine systems.

The existing power plant is a major facility in accordance with Rule 62-212.400, F.A.C., the regulatory program for the Prevention of Significant Deterioration (PSD) of Air Quality. It is located in Hillsborough County, an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. New projects at this major facility are subject to PSD preconstruction review. Based on a PSD netting analysis that included emissions decreases from the shutdown Gannon boilers as well as emissions increases from the new Bayside Units, the Department concluded that the proposed project requires a determination of the Best Available Control Technology (BACT) for emissions of carbon monoxide (CO), particulate matter (PM/PM10) and volatile organic compounds (VOC). As a result of previous settlement agreements with EPA and the Department, the netting analysis allowed only a portion of the emissions decreases from the shutdown Gannon boilers.

For CO, PM/PM10, and VOC emissions, the Department determined BACT to be the efficient combustion of clean fuels. The proposed gas turbines offer high temperatures, thorough mixing, and sufficient residence time to provide uniform combustion and low emission levels of these pollutants. Fuels are limited to pipeline-quality natural gas and distillate oil with no more than 0.05% sulfur by weight. A water injection system will be used to reduce NOx emissions when firing distillate oil. Only Units 3A and 3B are authorized to fire distillate oil. During simple cycle operations, Units 3A and 3B may fire oil up to 700 full load equivalent hours per year. After conversion to combined cycle operation, Units 3A and 3B are restricted to firing distillate oil only as an emergency backup fuel if natural gas is not available.

When Units 3 and 4 are constructed as combined cycle units, selective catalytic reduction (SCR) systems will be installed to reduce nitrogen oxide (NOx) emissions. Each gas turbine will be continuously monitored for emissions of carbon monoxide and nitrogen oxides.

Based on a separate PSD netting analysis, the Department determined that the project requires an air quality impact review for CO and VOC emissions. This netting analysis relied on the full actual emissions decreases from shutdown of the Gannon boilers to reflect expected actual impacts from this project. The project is not subject to an air quality impact review for particulate matter because actual emissions from the plant are expected to decrease by approximately 700 to 1000 tons per year.

No preconstruction monitoring or ambient impact analysis was required for VOC emissions because the potential increase was below the de minimis threshold of 100 tons per year established by rule. A significant impact analysis was conducted for CO emissions. The results predict a maximum 1-hour ambient CO concentration of 696.6 g/m3 and a maximum ambient 8-hour CO concentration of 224.8 g/m3. These levels are well below the regulatory thresholds and impacts from the project are not considered significant. No additional dispersion modeling was necessary. The applicant provided reasonable assurance that the project will not cause or contribute to adverse ambient air quality impacts.

Permitting Authority: Applications for air construction permits are subject to review in accordance with 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 proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114 and fax number is 850/921-9533.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Air Resources Section of the Department's Southwest District Office at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 (Telephone: 813/744-6100). A copy of the complete project file may also be available at the Air Management Division of the Hillsborough County Environmental Protection Commission at 1900 9th Avenue, Tampa, FL 33605 (Telephone: 813/272-5530).

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked, and all email or facsimile comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address, email or facsimile. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. 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 attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority 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 Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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 Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

8403 01/17/05

Memorandum Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief - Bureau of Air Regulation

THROUGH: Al Linero, Manager of Air Permitting South

FROM: Jeff Koerner, Air Permitting South JK

DATE: December 9, 2004

SUBJECT: TECO - H. L. Culbreath Bayside Power Station
Simple Cycle Units 3A and 3B with Distillate Oil Firing
Draft Air Permit No. PSD-FL-301C
Project No. 0570040-019-AC

Attached for your review are the following items:

- Intent to Issue Revised Air Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft Permit; and
- P.E. Certification.

The P.E. certification briefly summarizes the proposed permit project. The Technical Evaluation and Preliminary Determination provide a detailed description of the project, rationale, and conclusion. Day #74 is February 5, 2005. I recommend your approval of the attached Draft Permit for this project.

Attachments

P.E. CERTIFICATION STATEMENT

PERMITTEE

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

H. L. Culbreath Bayside Power Station
Draft Air Permit No. PSD-FL-301C
Project No. 0570040-019-AC
Units 3A/3B – Simple Cycle w/Oil

PROJECT DESCRIPTION

The existing H. L. Culbreath Bayside Power Station consists of Bayside Unit 1 (three combined cycle gas turbines) and Bayside Unit 2 (four combined cycle gas turbines). The current construction permit authorizes the installation of Bayside Units 3 and 4, each of which will consist of two combined cycle gas turbines. However, construction has not yet commenced on Units 3 and 4 and the permit expires in July of 2005. TECO proposes to initially install Units 3A and 3B as simple cycle units with the capability of firing distillate oil up to 700 full load equivalent hours per year. In the second construction phase, Unit 3 will be converted to combined cycle operation and Unit 4 will be added as a combined cycle unit.

The existing plant is a major facility in accordance with Rule 62-212.400, F.A.C., the regulatory program for the Prevention of Significant Deterioration (PSD) of Air Quality. Based on a PSD netting analysis, the project requires a determination of the Best Available Control Technology (BACT) for emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). See the Technical Evaluation and Preliminary Determination for specific details of this unique PSD netting analysis. The Department determined the following for this project.

- The fuel specification for natural gas is pipeline quality natural gas with no more than 2 grains of sulfur per 100 scf of natural gas based on a 12-month rolling average.
- The fuel specification for distillate oil is new No. 2 distillate oil with no more than 0.05% sulfur by weight. Only Units 3A and 3B are authorized to fire distillate oil. During simple cycle operations, Units 3A and 3B may fire oil for up to 700 full load equivalent hours per year. After conversion to combined cycle operation, Units 3A and 3B are restricted to firing distillate oil only as an emergency backup fuel in accordance with the EPA-TECO Consent Decree.
- BACT for CO is the efficient combustion of clean fuels. The CO BACT standard is 9.0 ppmvd @ 15% oxygen for all modes of operation and fuels. Compliance will be demonstrated by CEMS.
- The efficient combustion of clean fuels represents the Best Available Control Technology (BACT) requirements for PM/PM_{10} and VOC emissions. Compliance with CO and visible emissions standards will serve as continuous indicators of efficient combustion to minimize emissions of these pollutants. No performance tests are required for these pollutants.
- Compliance with the fuel sulfur specifications minimizes potential emissions of sulfuric acid mist and sulfur dioxide. No performance tests are required for these pollutants.
- During simple cycle operation, Units 3A and 3B shall achieve 24-hour NOx emission standards of 10.5 ppmvd @ 15% oxygen for gas firing based on DLN combustion technology and 42.0 ppmvd @ 15% oxygen for oil firing based on wet injection. Compliance will be demonstrated by CEMS.
- When Units 3 and 4 are constructed as combined cycle units, selective catalytic reduction (SCR) systems will be installed to reduce nitrogen oxide (NOx) emissions to no more than 3.5 ppmvd @ 15% oxygen when firing natural gas. If Units 3A and 3B fire distillate oil as an emergency backup fuel, the NOx emissions standard is 12.0 ppmvd @ 15% oxygen. Compliance will be demonstrated by CEMS.

The permit expiration date was specified as December 31, 2007. Any requests to extend the permit will require revalidation of the BACT determinations and a revised netting analysis.

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, geological, and meteorological features).*

Jeffery F. Koerner
12-29-04

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

(Date)

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

December 30, 2004

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

Re: Draft Air Permit No. PSD-FL-301C
Project No. 0570040-019-AC
H. L. Culbreath Bayside Power Station
Units 3A/3B – Simple Cycle Operation and Distillate Oil

Dear Mr. Maye:

The Tampa Electric Company (TECO) operates the existing H. L. Culbreath Bayside Power Station in Tampa at 3602 Port Sutton Road in Hillsborough County, Florida. TECO submitted an application to revise the current PSD air construction permit to add simple cycle operation and restricted distillate oil firing for Bayside Units 3A and 3B. Enclosed are the following documents: "Technical Evaluation and Preliminary Determination", "Draft Permit", "Written Notice of Intent to Issue Air Permit", and "Public Notice of Intent to Issue Air Permit".

The "Technical Evaluation and Preliminary Determination" summarizes the Bureau of Air Regulation's technical review of the application and provides the rationale for making the preliminary determination to issue a draft permit. The proposed "Draft Permit" includes the specific conditions that regulate the emissions units covered by the proposed project. The "Written Notice of Intent to Issue Air Permit" provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. The "Public Notice of Intent to Issue Air Permit" is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact the Project Engineer, Jeff Koerner, at 850/921-9536.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

In the Matter of an
Application for Air Permit by:

H. L. Culbreath Bayside Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

Authorized Representative:
Wade A. Maye, General Manager

Draft Air Permit No. PSD-FL-301C
Project No. 0570040-019-AC
H. L. Culbreath Bayside Power Station
Units 3A/3B – Simple Cycle/Oil Firing
Hillsborough County, Florida

Facility Location: The Tampa Electric Company (TECO) operates the existing H. L. Culbreath Bayside Power Station in Tampa at 3602 Port Sutton Road in Hillsborough County, Florida.

Project: TECO submitted an application to revise the current PSD air construction permit to add simple cycle operation and restricted distillate oil firing for Bayside Units 3A and 3B. The project also extends the period of time to construct combined cycle Units 3 and 4. Details of the project are provided in the application and the enclosed "Technical Evaluation and Preliminary Determination".

Permitting Authority: Applications for air construction permits are subject to review in accordance with 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 proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114 and fax number is 850/921-9533.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Air Resources Section of the Department's Southwest District Office at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 (Telephone: 813/744-6100). A copy of the complete project file may also be available at the Air Management Division of the Hillsborough County Environmental Protection Commission at 1900 9th Avenue, Tampa, FL 33605 (Telephone: 813/272-5530).

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "Public Notice of Intent to Issue Air Permit" (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet 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 Permitting Authority at the address or phone number listed above. Pursuant to Rule 62-110.106(5), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within seven (7) days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked, and all e-mail or facsimile comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address, email or facsimile. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. 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 attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority 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 Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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 Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the 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 12/30/04 to the persons listed below.

Mr. Wade A. Maye, TECO*
Ms. Greer Briggs, TECO
Ms. Raisa Calderon, TECO
Mr. Tom Davis, P.E., ECT
Mr. Jerry Kissel, SWD Office
Mr. Jerry Campbell, HEPC
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

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

[signature] (Clerk) 12/30/04 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 0570040-019-AC / Draft Air Permit No. PSD-FL-301C
TECO - H. L. Culbreath Bayside Power Station
Hillsborough County, Florida

Applicant: The applicant for this project is the Tampa Electric Company (TECO). The applicant's authorized representative is Mr. Wade A. Maye, General Manager of the H. L. Culbreath Bayside Power Station. The applicant's mailing address is: H. L. Culbreath Bayside Power Station, Tampa Electric Company, P.O. Box 111, Tampa, Florida 33601-0111.

Facility Location: TECO operates the existing H. L. Culbreath Bayside Power Station (formerly the F. J. Gannon Station) in Tampa at 3602 Port Sutton Road in Hillsborough County, Florida.

Project: TECO is permitted to construct four combined cycle gas turbines systems (Bayside Units 1 – 4) to re-power the former F.J. Gannon Station. All six coal-fired Gannon boilers have been permanently shutdown. However, only Bayside Units 1 and 2 have been constructed and are in operation. The applicant proposes a revision of the current PSD air construction permit to add a phase of simple cycle operation and restricted distillate oil firing for the Bayside Unit 3A and 3B gas turbines. In addition, the project will extend the period of time to construct Bayside Units 3 and 4 as combined cycle gas turbine systems.

The existing power plant is a major facility in accordance with Rule 62-212.400, F.A.C., the regulatory program for the Prevention of Significant Deterioration (PSD) of Air Quality. It is located in Hillsborough County, an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. New projects at this major facility are subject to PSD preconstruction review. Based on a PSD netting analysis that included emissions decreases from the shutdown Gannon boilers as well as emissions increases from the new Bayside Units, the Department concluded that the proposed project requires a determination of the Best Available Control Technology (BACT) for emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). As a result of previous settlement agreements with EPA and the Department, the netting analysis allowed only a portion of the emissions decreases from the shutdown Gannon boilers.

For CO, PM/PM_{10}, and VOC emissions, the Department determined BACT to be the efficient combustion of clean fuels. The proposed gas turbines offer high temperatures, thorough mixing, and sufficient residence time to provide uniform combustion and low emission levels of these pollutants. Fuels are limited to pipeline-quality natural gas and distillate oil with no more than 0.05% sulfur by weight. A water injection system will be used to reduce NOx emissions when firing distillate oil. Only Units 3A and 3B are authorized to fire distillate oil. During simple cycle operations, Units 3A and 3B may fire oil up to 700 full load equivalent hours per year. After conversion to combined cycle operation, Units 3A and 3B are restricted to firing distillate oil only as an emergency backup fuel if natural gas is not available. When Units 3 and 4 are constructed as combined cycle units, selective catalytic reduction (SCR) systems will be installed to reduce nitrogen oxide (NOx) emissions. Each gas turbine will be continuously monitored for emissions of carbon monoxide and nitrogen oxides.

Based on a separate PSD netting analysis, the Department determined that the project requires an air quality impact review for CO and VOC emissions. This netting analysis relied on the full actual emissions decreases from shutdown of the Gannon boilers to reflect expected actual impacts from this project. The project is not subject to an air quality impact review for particulate matter because actual emissions from the plant are expected to decrease by approximately 700 to 1000 tons per year.

No preconstruction monitoring or ambient impact analysis was required for VOC emissions because the potential increase was below the de minimis threshold of 100 tons per year established by rule. A significant impact analysis was conducted for CO emissions. The results predict a maximum 1-hour ambient CO concentration of 696.6 $\mu g/m^3$ and a maximum ambient 8-hour CO concentration of 224.8 $\mu g/m^3$. These levels are well below the regulatory thresholds and impacts from the project are not considered significant. No additional dispersion modeling was necessary. The applicant provided reasonable assurance that the project will not cause or contribute to adverse ambient air quality impacts.

Permitting Authority: Applications for air construction permits are subject to review in accordance with 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 proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114 and fax number is 850/921-9533.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Air Resources Section of the Department's Southwest District Office at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 (Telephone: 813/744-6100). A copy of the complete project file may also be available at the Air Management Division of the Hillsborough County Environmental Protection Commission at 1900 9th Avenue, Tampa, FL 33605 (Telephone: 813/272-5530).

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked, and all email or facsimile comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address, email or facsimile. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. 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 attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority 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 Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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 Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

P.E. CERTIFICATION STATEMENT

PERMITTEE

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

H. L. Culbreath Bayside Power Station
Draft Air Permit No. PSD-FL-301C
Project No. 0570040-019-AC
Units 3A/3B – Simple Cycle w/Oil

PROJECT DESCRIPTION

The existing H. L. Culbreath Bayside Power Station consists of Bayside Unit 1 (three combined cycle gas turbines) and Bayside Unit 2 (four combined cycle gas turbines). The current construction permit authorizes the installation of Bayside Units 3 and 4, each of which will consist of two combined cycle gas turbines. However, construction has not yet commenced on Units 3 and 4 and the permit expires in July of 2005. TECO proposes to initially install Units 3A and 3B as simple cycle units with the capability of firing distillate oil up to 700 full load equivalent hours per year. In the second construction phase, Unit 3 will be converted to combined cycle operation and Unit 4 will be added as a combined cycle unit.

The existing plant is a major facility in accordance with Rule 62-212.400, F.A.C., the regulatory program for the Prevention of Significant Deterioration (PSD) of Air Quality. Based on a PSD netting analysis, the project requires a determination of the Best Available Control Technology (BACT) for emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). See the Technical Evaluation and Preliminary Determination for specific details of this unique PSD netting analysis. The Department determined the following for this project.

- The fuel specification for natural gas is pipeline quality natural gas with no more than 2 grains of sulfur per 100 scf of natural gas based on a 12-month rolling average.
- The fuel specification for distillate oil is new No. 2 distillate oil with no more than 0.05% sulfur by weight. Only Units 3A and 3B are authorized to fire distillate oil. During simple cycle operations, Units 3A and 3B may fire oil for up to 700 full load equivalent hours per year. After conversion to combined cycle operation, Units 3A and 3B are restricted to firing distillate oil only as an emergency backup fuel in accordance with the EPA-TECO Consent Decree.
- BACT for CO is the efficient combustion of clean fuels. The CO BACT standard is 9.0 ppmvd @ 15% oxygen for all modes of operation and fuels. Compliance will be demonstrated by CEMS.
- The efficient combustion of clean fuels represents the Best Available Control Technology (BACT) requirements for PM/PM_{10} and VOC emissions. Compliance with CO and visible emissions standards will serve as continuous indicators of efficient combustion to minimize emissions of these pollutants. No performance tests are required for these pollutants.
- Compliance with the fuel sulfur specifications minimizes potential emissions of sulfuric acid mist and sulfur dioxide. No performance tests are required for these pollutants.
- During simple cycle operation, Units 3A and 3B shall achieve 24-hour NOx emission standards of 10.5 ppmvd @ 15% oxygen for gas firing based on DLN combustion technology and 42.0 ppmvd @ 15% oxygen for oil firing based on wet injection. Compliance will be demonstrated by CEMS.
- When Units 3 and 4 are constructed as combined cycle units, selective catalytic reduction (SCR) systems will be installed to reduce nitrogen oxide (NOx) emissions to no more than 3.5 ppmvd @ 15% oxygen when firing natural gas. If Units 3A and 3B fire distillate oil as an emergency backup fuel, the NOx emissions standard is 12.0 ppmvd @ 15% oxygen. Compliance will be demonstrated by CEMS.

The permit expiration date was specified as December 31, 2007. Any requests to extend the permit will require revalidation of the BACT determinations and a revised netting analysis.

***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, geological, and meteorological features).*

Jeffery F. Koerner — 12-29-04

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

(Date)

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

H. L. Culbreath Bayside Power Station
Project to Re-Power the F. J Gannon Station

Revision to Units 3A and 3B
Simple Cycle Operation and Distillate Oil Firing

Project No. 0570040-019-AC
Draft Permit No. PSD-FL-301C

COUNTY

Hillsborough County, Florida

APPLICANT

Tampa Electric Company
H. L. Culbreath Bayside Power Station
3602 Port Sutton Road
Tampa, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation - Air Permitting South
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

December 9, 2004

Filename: PSD-FL-301C - TEPD

1. APPLICATION INFORMATION

Applicant and Facility Description

The Tampa Electric Company operates the H. L. Culbreath Bayside Power Station located at 3602 Port Sutton Road in Tampa, Florida. The existing electrical generating plant consists of combined cycle Units 1 and 2 with a nominal generating capacity of approximately 1836 MW. The Standard Industrial Classification (SIC) code for this facility is Industry No. 4911, Electric Services. The primary regulatory categories are as follows.

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

Title IV: All Bayside gas turbines are subject to the Phase II Acid Rain requirements. All Gannon boilers have been permanently shutdown and are considered "retired units" in accordance with the Acid Rain provisions.

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

Site Certification: The facility is not subject to any specific power plant site certification requirements.

PSD: The facility is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

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

NESHAP: The re-powered facility is not a major source of hazardous air pollutants; therefore the National Emissions Standards for Hazardous Air Pollutants in Subpart YYYY of 40 CFR 63 do not apply to the gas turbines.

Project Description

The DEP-TECO Consent Final Judgment (December of 1999) and the EPA-TECO Consent Decree (February of 2000) required the Tampa Electric Company (TECO) to permanently shutdown the coal-fired boilers at the existing F. J. Gannon Plant and re-power some of the steam-turbine electrical generators with natural gas. As a result, the Department issued the following related air permits.

- In March of 2001, the Department issued Permit No. PSD-FL-301 for the Bayside Power Station to authorize construction of combined cycle gas turbine Units 1and 2 to re-power existing Gannon steam-electrical generators 5 and 6. The seven combined cycle gas turbines were permitted to fire natural gas and up to 875 full load equivalent hours of distillate oil as an emergency backup fuel.
- In January of 2002, the Department issued revised Permit No. PSD-FL-301A to also authorize construction of combined cycle gas turbine Units 3 and 4 to re-power existing Gannon steam-electrical generators 3 and 4. The eleven combined cycle gas turbines were permitted to fire only natural gas.
- In November of 2004, the Department issued Permit No. PSD-FL-301B to revise Condition 17 related to low load operations and CEMS data exclusion due to startup, shutdown, malfunction, DLN tuning, compressor blade drying, and over speed trip testing.

In accordance with the settlement agreements and permits, the Gannon boilers were officially shut down on the following dates: Unit 1 (04/16/03); Unit 2 (04/15/03); Unit 3 (11/01/03); Unit 4 (10/12/03); Unit 5 (01/30/03); and Unit 6 (09/30/03). The Gannon coal yard (EU 008) remains operable, but is presently idle. Construction of Bayside Unit 1 is complete and commercial operation began on March 16, 2003. Construction of Bayside Unit 2 is complete and commercial operation began on November 19, 2003. TECO has not yet commenced construction of Bayside combined cycle Units 3 and 4.

With this project, TECO requests the authority to construct Bayside Units 3A and 3B as "simple cycle units" with the capability of firing distillate oil restricted to 700 full load equivalent hours per year. Units 3A and 3B will later be converted to combined cycle operation and Unit 4 added as a two-on-one combined cycle unit. The details are provided below.

- Simple Cycle Units 3A and 3B: Each new simple cycle unit will consist 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 exhaust stack that is 114 feet tall and 18.8 feet in diameter, and associated support equipment. At a compressor inlet air temperature of 59° F and firing 1842 MMBtu (HHV) per hour of natural gas, each unit produces a nominal 169 MW of shaft-driven electricity. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,394,000 acfm at 1120° F. At a compressor inlet air temperature of 59° F and firing 2015 MMBtu (HHV) per hour of distillate oil, each unit produces a nominal 169 MW of shaft-driven electricity. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,469,000 acfm at 1100° F.
- Combined Cycle Units 3 and 4: Combined cycle Unit 3 consists of two gas turbines to re-power the steam turbine electrical generator (163 MW) for Gannon Unit 3. Combined cycle Unit 4 consists of two gas turbines to re-power the steam turbine electrical generator (170 MW) for Gannon Unit 4. Each gas turbine system 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), an 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. At a compressor inlet air temperature of 59° F and firing 1842 MMBtu (HHV) per hour of natural gas, each unit produces a nominal 169 MW of shaft-driven electricity. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,000 acfm at 220° F. Natural gas is the exclusive fuel for Unit 4, but Unit 3 may burn distillate oil as an emergency backup fuel in accordance with the provisions in the EPA-TECO Consent Decree.

Based on the information provided in the application, the new project for simple cycle operation of Units 3A and 3B triggers PSD preconstruction review for emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). For these pollutants, the applicant requests that the following be determined as the Best Available Control Technology (BACT): The efficient combustion of natural gas and distillate oil at the high temperatures produced by the gas turbines will minimize emissions of CO, PM/PM_{10}, and VOC. The firing of these low-sulfur fuels will also minimize emissions of sulfuric acid mist (SAM) and sulfur dioxide (SO_2). For the simple cycle Units 3A and 3B, NOx emissions will be reduced with General Electric's dry low-NOx combustion system when firing natural gas and with water injection when firing distillate oil. The applicant also requests future conversion of Units 3A and 3B to combined cycle operation as well as maintaining the current authorization to install Unit 4 as a combined cycle unit. For combined cycle Units 3 and 4, a selective catalytic reduction (SCR) system will be added to further reduce NOx emissions.

2. RULE APPLICABILITY

State Regulations

The 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 Chapters of the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-204	Ambient Air Quality Standards, PSD Increments, and Federal Regulations Adopted by Reference
62-210	Required Permits, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms
62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements

62-296	Emission Limiting Standards
62-297	Test Requirements, Test Methods, Supplementary Test Procedures, CEMS, and Alternate Sampling Procedures

Federal Regulations

This project is also subject to the following federal provisions regarding air quality as established by the United States Environmental Protection Agency (EPA) in Title 40 of the Code of Federal Regulations (CFR).

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
	Subpart A, General Provisions for NSPS Sources
	Subpart GG, NSPS for Stationary Gas Turbines
	Applicable NSPS Appendices
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain - Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions

The federal acid rain requirements will be incorporated into the Title V air operation permit after the units are constructed and initial operation has commenced.

General PSD Applicability

The Department regulates major air pollution facilities in accordance with the Prevention of Significant Deterioration (PSD) program, as approved by the EPA in Florida's State Implementation Plan and defined in Rule 62-212.400, F.A.C. A PSD preconstruction review is required in areas currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for a given pollutant. A facility is considered "major" with respect to PSD if it 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 PSD Major Facility Categories (Table 62-212.400-1, F.A.C.), or 5 tons per year of lead.

For new projects at existing 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 and evaluate the air quality impacts. 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.

PSD Applicability for the Project

The H. L. Culbreath Bayside Power Station is an existing facility located in Hillsborough County, which is an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. The actual and potential annual emissions of several pollutants from the facility are greater than the applicability thresholds defined above. Therefore, the power plant is an existing PSD-major facility as defined in Rule 62-212.400, F.A.C.

The project includes a netting analysis that uses emissions decreases from the shutdown of the coal-fired Gannon boilers to offset the emissions increases from the new Bayside Units. Typically, a netting analysis compares the future potential emissions after the project is complete to the past actual emissions before the project to determine whether there will be a net emissions increase that triggers PSD preconstruction review.

However, the re-powering project is the result of enforcement actions regarding the timely implementation of new source preconstruction review for the existing Gannon Units. Therefore, the applicant may not take credit for emissions decreases that would not have been available if appropriate Best Available Control Technologies (BACT) had been previously installed.

For the original projects, (PSD-FL-301 and PSD-FL-301A), the Department determined that the full past actual emissions from the Gannon boilers could be used to determine the PSD modeling requirements. However, to determine which pollutants were subject to PSD BACT review, the past actual emissions from the Gannon Units were adjusted downward based on the Department's most recent BACT determinations for a coal-fired boiler (Indiantown Cogeneration Plant, PSD-FL-168A). Past actual emissions from the Gannon Units were adjusted downward by the estimated control efficiencies for: an improved electrostatic precipitator for particulate matter (> 99.9%); a lime spray dryer for sulfur dioxide (95%); and a selective catalytic reduction system for nitrogen oxides (92%). For the remainder of this Technical Evaluation, the reduced past actual emissions will be referred to as "adjusted" past actual emissions (or decreases). Based on this method, both projects were subject to PSD BACT review for CO, PM/PM_{10}, and VOC emissions.

In 2001, the EPA-TECO Consent Decree was amended to formalize this method as follows.

"Add new paragraph 86.1, as follows: "86.1 Netting: For any and all emission control actions taken by Tampa Electric to comply with the terms of this Consent Decree, including but not limited to upgrading of ESPs and scrubbers, installation of scrubbers, installations of SCRs, and the Re-powering of Gannon or Big Bend Units, any emission reductions generated thereby shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit under the Clean Air Act's New Source Review program, provided, however, that nothing in this Decree shall be construed to prohibit Tampa Electric's seeking such treatment for emissions decreases resulting from the difference in emissions between:

(i) those that would have resulted from installing on an existing Gannon or Big Bend coal-fired Unit: an SCR that maintains 0.10 lb/MMBtu NOx Emission Rate, a scrubber that maintains and SO_2 removal efficiency of 95%, and an ESP that maintains a PM Emission Rate of less than 0.010 lb/MMBtu, and

(ii) those that result from Re-powering that same Unit and meeting a NOx Emission Rate of no greater than 3.5 ppm."

During review of the current project, the Department had several discussions with EPA Region 4 regarding the netting analysis and the interpretation of the amendment to the EPA-TECO Consent Decree. Initially, EPA indicated that net decreases from the shutdown of the Gannon boilers may not be used for the simple cycle project because no unit was being re-powered. Upon further consideration, EPA Region 4 now interprets the amendment to mean that only "adjusted" decreases from Gannon Units that have been re-powered (or will be re-powered as part of a project) may be used in a netting analysis for a new project. To clarify, EPA does not believe that "adjusted" decreases from the shutdown of Gannon Units 1 and 2 can be used in a netting analysis because these units are not part of any project to be re-powered. However, based on the state PSD regulations, the Department believes that "adjusted" decreases for any Gannon Unit that has been permanently shutdown may be available for use in a netting analysis.

PSD Preconstruction Review for Best Available Control Technology (BACT)

To satisfy EPA Region 4's concerns regarding the proposed project, the Department performed separate netting analyses for the following cases to determine which pollutants were subject to a BACT review.

- *Simple Cycle Case*: This netting analysis compares the potential emissions from combined cycle Bayside Units 1 and 2 plus simple cycle Bayside Units 3A and 3B with "adjusted" past actual emissions (decreases) from Gannon Units 5 and 6. Only the "adjusted" past actual emissions from Gannon Units 5 and 6 are considered because these are the only units that have been re-powered to date.
- *Combined Cycle Case*: This netting analysis compares the potential emissions from combined cycle

Bayside Units 1 through 4 with "adjusted" past actual emissions (decreases) from Gannon Units 3 - 6. Only the "adjusted" past actual emissions from Gannon Units 3 - 6 are considered because these are the only units that have been re-powered or are part of a project to be re-powered.

For each case, potential annual emissions from the Bayside Units are based on permitted emissions rates at full load conditions and a compressor inlet temperature of 59° F. Past actual emissions from the Gannon Units are based on the federal Acid Rain data (for nitrogen oxides, particulate matter, and sulfur dioxide) and state Annual Operating Report data (for carbon monoxide and volatile organic compounds). Past actual emissions from the Gannon Units are then "adjusted" downward based on the provisions in the amended EPA-TECO Consent Decree. For complete details of the netting analyses, see Attachments A and B at the end of this Technical Evaluation and Preliminary Determination. As shown, the project triggers a BACT review for CO, PM/PM_{10}, and VOC emissions for each case.

PSD Preconstruction Review for Air Quality Analysis

The Department also performed separate netting analyses for the simple cycle and combined cycle cases to determine which pollutants were subject to a PSD air quality modeling review. These netting analyses differ with those for the PSD BACT review because the past actual emissions from the Gannon Units *are not* adjusted downward. Instead, the full emissions decreases that will be realized are used for determining the air quality modeling requirements. This more closely matches actual expected impacts to the environment and is consistent with the review for the original projects. For complete details of this netting analysis, see Attachments A and B at the end of this Technical Evaluation and Preliminary Determination. As shown, the project triggers a PSD air quality analysis only for CO and VOC emissions because the project will actually *decrease* particulate matter emissions by approximately 700 tons per year for the simple cycle case and 1000 tons per year for the combined cycle case.

Summary

Based on the Department's review, the simple cycle and combined cycle scenarios both trigger BACT reviews for CO, PM/PM_{10}, and VOC emissions and an air quality analyses for CO and VOC emissions. Although different methodologies are used, the resulting conclusion is consistent with the applicant's regarding the PSD preconstruction review requirements. Although Units 3 and 4 were originally permitted for combined cycle operation, no construction has yet commenced on these units and the authority to construct expires on July 1, 2005. Therefore, the Department will take this opportunity to re-validate the original BACT determinations made in January of 2002 for combined cycle Units 3 and 4.

3. BACT REVIEW FOR CO, PM/PM_{10}, AND VOC EMISSIONS

Discussion

Gas turbines emit carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC) based on the types of fuels fired and the efficiency of the combustion process. Particulate matter emissions are primarily caused by the ash content of the fuel. For many combustion processes, CO/VOC emissions are inversely proportional to NOx emissions. However, the dry low-NOx combustor design for General Electric's Frame 7FA gas turbine has also successfully reduced CO/VOC emissions concurrently with NOx emissions. This system produces high temperatures, adequate residence time, and sufficient turbulence which results in uniform combustion throughout the lean pre-mix system. Such uniform combustion minimizes the "hot spots" that produce thermal NOx and the "cold spots" that result in CO/VOC emissions from incomplete combustion. In addition, the dual fuel combustion system of the General Electric Model PG7241(FA) gas turbine provides similarly efficient combustion of distillate oil with low CO/VOC emissions.

Applicant's Proposal for CO/VOC Emissions

For gas turbines, catalytic oxidation is generally recognized as the top add-on control option. A catalytic oxidation system consists of a noble metal catalyst section incorporated into the gas turbine exhaust stream. 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. Based on the expected uncontrolled emission levels, CO control efficiencies could approach 90%, but VOC control efficiencies would more likely be in the 30 - 50% range.

The applicant recognized a catalytic oxidation system as the top control for CO and VOC emissions, but identified the following additional adverse impacts.

Energy Impacts: Installation of a catalytic oxidation system results in a pressure drop across the catalyst bed of approximately 1.1 inch of water column. This pressure drop causes backpressure on the gas turbine and reduces the power output from the unit resulting in an energy penalty of approximately 0.26%. The applicant estimates the lost power generation to be 5,261,256 kWh, which is equivalent to approximately $157,838 per year per gas turbine based on a power cost of $0.03/kWh.

Environmental Impacts: The catalytic oxidation system would oxidize some of the fuel sulfur present in natural gas and distillate oil to sulfuric acid mist. Due to the inherently low CO and VOC emissions from the Model PG7241(FA) gas turbine, the applicant contends that the addition of a catalytic oxidation system 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 a catalytic oxidation system would result in total capital investment of approximately $3,559,255 per gas turbine with a total annualized cost of approximately $744,092 per year per gas turbine. Assuming 90% control efficiency, the catalytic oxidation system would remove an additional 132 tons of CO per year per gas turbine resulting in a cost effectiveness of approximately $5600 per ton of CO removed. Assuming 50% control efficiency, the catalytic oxidation system would remove an additional 7.5 tons of VOC per year per gas turbine resulting in a separate cost effectiveness of more than $99,000 per ton of VOC removed.

The applicant primarily rejected the catalytic oxidation system as not cost effective for the project, but also noted the adverse energy and environmental impacts summarized above. The applicant proposed the following CO and VOC emissions standards for the simple cycle gas turbines based on the efficient combustion design of the Model PG7241(FA) and good operating practices.

Requested CO Standards:	7.8 ppmvd corrected to 15% oxygen (33.0 lb/hour) for natural gas
	30.3 ppmvd corrected to 15% oxygen (136.4 lb/hour) for distillate oil
Requested VOC Standards:	1.2 ppmvd corrected to 15% oxygen (3.0 lb/hour) for natural gas
	3.0 ppmvd corrected to 15% oxygen (8.0 lb/hour) for distillate oil

Note that the mass emission rates are based on full load operation at a compressor inlet temperature of 59° F.

Department's BACT Review for CO/VOC Emissions

Background

CO and VOC emissions from gas turbines are primarily the result of incomplete fuel combustion. Most new gas turbines incorporate modern, high-temperature combustion designs that provide sufficient mixing and residence times to minimize emissions of CO and VOC. The Department agrees that the top add-on control option is an oxidation catalyst.

In the past, oxidation catalysts have been required on less efficient units, particularly those that do not perform well at low load conditions. Manufacturers have also been reluctant to guarantee the very low emissions that are within the actual capabilities of the units in operation. This has lead to relatively high BACT determinations or the requirement to install an oxidation catalyst on a unit that actually emits low CO/VOC emissions. The

General Electric Model PG7241(FA) gas turbine exhibits low NOx emissions as well as low CO/VOC emissions down to approximately 45% of full load operation.

The Department's most recent CO/VOC BACT determination for a similar gas turbine project is the application for Unit 5 at FPL's Turkey Point Plant, which consists of four General Electric 7FA gas turbines operating as a four-on-one combined cycle unit. The following bulleted items are taken from the Technical Evaluation and Preliminary Determination for the FPL Turkey Point project.

- General Electric 7FA units achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing natural gas at the City of Tallahassee's Purdom Unit 8 and TECO's Polk Power Station Unit 2 based on tests conducted between 50% and 100% of full load. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Notably, the emissions of the General Electric 7FA units without oxidation catalyst systems matched those of the ABB gas turbines at the ANP Blackstone Energy Company project in Massachusetts that were equipped with oxidation catalysts.
- Similarly, VOC emissions less than 1 ppm have consistently been measured at new General Electric 7FA units throughout the state. Again, the results are roughly equal to those of the ABB gas turbines at the ANP Blackstone Energy Company project in Massachusetts that were equipped with oxidation catalysts.
- Based on the Department's review, the following table shows CO and VOC emissions data for General Electric 7FA gas turbines collected when firing distillate oil at several existing facilities.

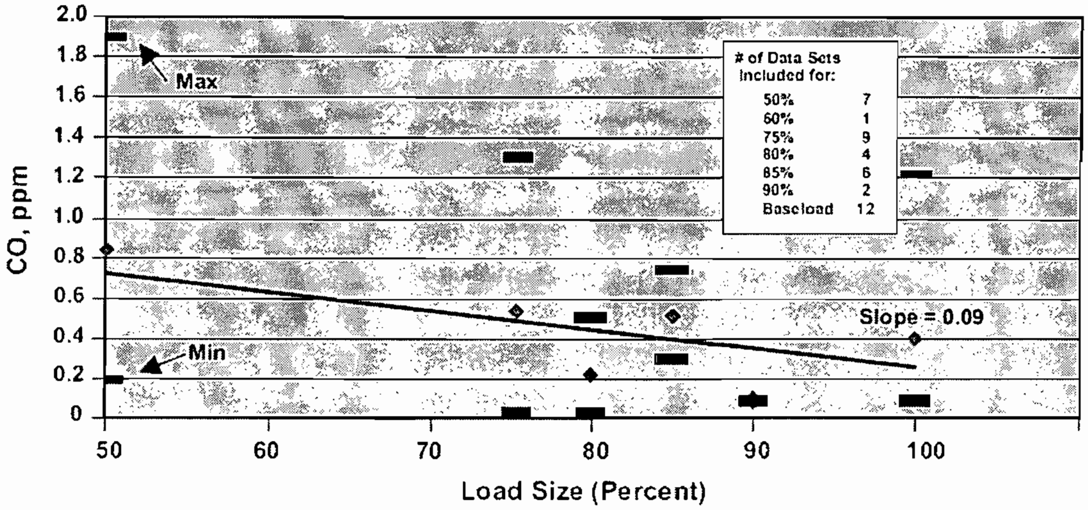
Facility/Unit (% Load)	CO, ppmvd @15% O2	VOC, ppmvd @15% O2
Martin Unit 8A (100%)	0.6	0.4
Martin Unit 8B (100%)	0.8	0.4
Purdom Unit 8 (~50%)	1.2	---
Purdom Unit 8 (100%)	1.3	---
TECO Polk Unit 3 (100%)	0.6	0.1
JEA Kennedy KCT-7 (100%)	2.1	1.1
Stanton A – Unit 25 (100%)	1.0	1.1
Stanton A – Unit 26 (100%)	1.0	0.8
Reliant Osceola Unit 1 (100%)	0.04	0.18
Reliant Osceola Unit 2 (100%)	0.02	0.01
Reliant Osceola Unit 3 (100%)	0.54	0.00
Oleander Power Unit 1 (100%)	1.8	< 0.7
Oleander Power Unit 2 (100%)	1.1	< 0.7
Oleander Power Unit 3 (100%)	3.8	< 0.7
Oleander Power Unit 4 (100%)	2.7	< 0.7

  There are no appreciable differences in CO/VOC emissions for large gas turbines when they are operated on distillate oil versus natural gas. This conclusion is noteworthy because wet injection for basic NOx control is practiced on all such units when firing distillate oil.

- CO and VOC emissions *should* be low because of the very high combustion temperatures, excess air, and turbulence characteristics of the General Electric 7FA gas turbine. Performance guarantees are only now "catching up" with the actual field experience.
- General Electric recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its 7FA units. The report states, *"GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN on a case-by-case basis following a detailed evaluation of the situation - thus validating*

its position that oxidation catalysts are not economically justified for CO emissions reduction for the GE PG7241FA DLN units while firing natural gas." {General Electric Technical Report No. 4213. Davis, L.B. and Black, S.H. GE Power Systems. "Support for Elimination of Oxidation Catalyst Requirements for GE PG7242FA DLN Combustion Turbines." August 2001.}

- The following figure from General Electric's report is consistent with the data collected by the Department and supports the Department's analysis of this technical issue.



- For the Turkey Point project, FPL obtained CO emissions guarantees of 4.1 and 8.0 ppmvd @ 15% oxygen when firing natural gas and distillate oil, respectively. General Electric estimated the cost to further reduce CO emissions from the guaranteed rates at $8000 per ton. These values represent the lowest guarantees yet without the need for an oxidation catalyst. For the Turkey Point project, the Department's BACT determination was set at 8.0 ppmvd @ 15% oxygen when firing either natural gas or distillate oil.

Bayside Unit 1 - Emissions Data

Natural gas is the exclusive fuel for Bayside Unit 1, which began commercial operation on March 16, 2003. The Department reviewed the semiannual excess emissions reports from the second quarter through the fourth quarters of 2003 for the three gas turbines associated with this unit. This represents more than 200 actual operating days. Based on Continuous Emissions Monitoring System (CEMS) data, the reports indicate the following with regard to CO emissions from the Bayside Unit 1 gas turbines operating on natural gas.

- Excess CO emissions have only been reported during periods of startup, shutdown or malfunctions when the dry low NOx combustion system was not in full lean pre-mixed combustion mode.
- Very low CO emissions (< 2 ppmvd @ 15% oxygen) are achievable at low operating loads (~50%).
- For a properly tuned gas turbine, CO emissions when firing natural gas are typically less than 1 ppmvd @ 15% oxygen.
- All but five of the 24-hour CO emissions averages were less than 2 ppmvd @ 15% oxygen. The highest 24-hour CO emissions average was 5.8 ppmvd @ 15% oxygen for Unit 1C during the second quarter of 2003.

Conclusion

General Electric now provides guaranteed CO emissions levels of 4.1 @ 15% oxygen when firing natural gas and 8.0 ppmvd @ 15% oxygen when firing distillate oil. Stack test data for similar General Electric 7FA gas turbines shows that actual CO emissions when firing distillate oil are much less than 8 ppmvd @ 15% oxygen. Actual CEMS operating data for Bayside Unit 1 indicates CO emissions when firing natural gas will be less than 2 ppmvd @ 15% oxygen. At these actual operating levels, the addition of an oxidation catalyst would not be cost effective.

The CO BACT standard for existing Bayside Units 1 and 2 when firing natural gas is 9.0 ppmvd @ 15% oxygen (CEMS, 24-hour average). The Department's most recent CO BACT determinations for a General Electric Model PG7241FA gas turbine (FPL Turkey Point Project) is 8.0 ppmvd @ 15% oxygen based on a 24-hour average when firing either natural gas or distillate oil. Based on the available information and the previous BACT determinations for Bayside Units 1 and 2, the Department makes the following draft BACT determinations.

CO BACT: 7.8 ppmvd corrected to 15% oxygen (33.0 lb/hour) for natural gas, new and clean stack test

9.0 ppmvd corrected to 15% oxygen (40.5 lb/hour) for distillate oil, new and clean stack test

9.0 ppmvd corrected to 15% oxygen based on a 24-hour CEMS average (gas or oil)

VOC BACT: The efficient combustion of clean fuels represents the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with carbon monoxide standards shall serve as a continuous indicator of efficient combustion to minimize VOC emissions. No performance tests for VOC emissions are required. *{Note: As indicated by the applicant and available test data, VOC emission levels are expected to be less than 1.2 ppmvd corrected to 15% oxygen when firing natural gas and 3.0 ppmvd corrected to 15% oxygen when firing distillate oil.}*

The above determinations establish the draft BACT standards for simple cycle operation of Units 3A and 3B as well as revalidate the initial BACT determinations for combined cycle Bayside Units 3 and 4. The CEMS-based standard provides a small margin above General Electric's available guarantee of 8.0 ppmvd for distillate oil firing. It also allows some consideration for previous determinations made for Bayside Units 1 and 2, which are identical units that are now in operation. This should simplify the record keeping and compliance activities at the plant. The continuous CO emissions monitors will verify the actual low emissions levels and the efficient combustion of the lean premix gas turbines. The BACT determinations are valid for both simple cycle and combined cycle operations because they rely on the same technology, i.e., the efficient combustion design of the General Electric Model PG7241FA when firing clean fuels.

Applicant's Proposal for PM/PM_{10} Emissions

The estimated uncontrolled particulate matter emission rates when firing pipeline-quality natural gas and distillate oil are 0.003 grains/dscf and 0.005 grains/dscf, respectively. The applicant indicates that installing add on controls (baghouses, electrostatic precipitators, wet scrubber, etc.) for this level of emissions would result in excessive costs and is not appropriate for this application. Therefore, the efficient combustion design and firing of clean fuels is requested as BACT for particulate matter emissions. In addition, the testing of simple cycle gas turbines is difficult due to the large volumes of exhaust gas flow, very high temperatures (> 1000° F), and very low particulate matter emissions. Therefore, the applicant requests a visible emissions work practice standard of 10% opacity (6-minute block average) as an indicator of efficient combustion.

Department's BACT Review for PM/PM_{10} Emissions

Particulate matter emissions from gas turbines are primarily the result of the fuel type and incomplete fuel combustion. Gas turbines require clean fuels to avoid damaging turbine blades and other components that are already exposed to very high temperatures and pressures. These units also incorporate large inlet air filtration systems to prevent particulate matter in the ambient air from damaging the gas turbines. The applicant proposes to fire pipeline natural gas as the primary fuel and distillate oil (≤ 0.05% sulfur by weight) as a restricted backup fuel. Natural gas is an inherently clean fuel that contains no ash. Distillate oil contains minimal amounts of ash and operation will be limited to no more than an equivalent of 700 full load hours of distillate oil per year.

General Electric typically lists particulate matter emissions of 9 lb/hour for gas firing and 17 lb/hour for distillate oil firing. This is a very conservative estimate of the particulate matter that would be captured on a filter during an EPA Method 5 test. Condensable particulate matter captured in the back half of the EPA Method 5 train could conceivably double these amounts. Based on information provided by General Electric for the FPL Turkey Point Unit 5 project, total particulate matter emissions (filterable and condensable) averaged approximately 14 lb/hour when firing natural gas and approximately 24 lb/hour when firing distillate oil. Ammonia injection for units with SCR systems can increase emissions of fine particulate matter due to the formation of ammonium sulfates. Nevertheless, uncontrolled particulate matter emissions from these large frame gas turbines (< 0.012 lb/MMBtu, < 11.5 mg/dscm) are quite low in comparison with other combustion sources such as a new solid fuel-fired industrial boiler subject to NESHAP Subpart DDDDD (ESP or fabric filter ≤ 0.025 lb/MMBtu) or a new municipal waste combustor subject to NSPS Subpart Eb (ESP or fabric filter ≤ 24 mg/dscm).

The Department agrees that add on controls for particulate matter emissions would be cost prohibitive, impractical or both due to the large flow rates, low uncontrolled emission rates, and high exhaust temperatures associated with large frame gas turbines. Particulate matter emissions will be minimized by the use of clean fuels and efficient combustion. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration for this project. Therefore, the following conditions are established as the draft BACT determinations for particulate matter emissions.

PM BACT: BACT is determined to be the efficient combustion of clean fuels meeting the following specifications: pipeline-quality natural gas (≤ 2 grains of sulfur per 100 scf, 12-month rolling average) and distillate oil (≤ 0.05% sulfur by weight) restricted to an equivalent of 700 full load hours of operation. In addition, visible emissions shall not exceed 10% opacity based on a 6-minute average.

Compliance with carbon monoxide and visible emissions standards shall serve as continuous indicators of efficient combustion. Compliance with the visible emissions standard shall be demonstrated by conducting initial and annual opacity observations in accordance with EPA Method 9. No other performance tests for particulate matter are required.

The above BACT determinations are valid for both simple cycle and combined cycle operations because they rely on the same technology, i.e., the efficient combustion design of the General Electric Model PG7241FA when firing clean fuels.

Department's Consideration of the Phased Projects

Issued in 2002, Permit No. PSD-FL-301A authorized construction of combined cycle Units 1 through 4 and recognized a phased construction schedule. Construction of Bayside Unit 1 is complete and commercial operation began on March 16, 2003. Construction of Bayside Unit 2 followed and commercial operation began on November 19, 2003. However, construction of Bayside Units 3 and 4 has not yet begun and Permit No. PSD-FL-301A expires in July of 2005.

With this project, the applicant requests initial construction of Bayside Units 3A and 3B as simple cycle gas turbines. These units will later be converted to combined cycle units and Unit 4 will be installed as a two-on-one combined cycle unit. With the issuance of the revised permit, the Department revalidates the initial BACT determinations made for Bayside Units 3 and 4 as described above.

Rule 40 CFR 52.21(r)(2) states, "Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date." Due to the phased nature and specific details of this project, the revised permit will specify the following.

- Construction of Bayside Units 3A and 3B shall commence within 18 months after permit issuance. Otherwise, authorization to construct shall become invalid.
- Conversion of Units 3A and 3B to combined cycle operation shall be complete before this permit expires. Otherwise, the Department will require revalidation of the BACT determinations and a new netting analysis for any requests to extend the permit. *{Note that the BACT determinations for CO, PM/PM_{10}, and VOC are the same for simple cycle and combined cycle operation.}*
- Construction of combined cycle Unit 4 shall be complete before this permit expires. Otherwise, the Department will require revalidation of the BACT determinations and a new netting analysis for any requests to extend the permit. *{Note that some consideration is being given to the staggered construction schedule for the project.}*

In addition, the permit expiration date will be set at December 31, 2007. This ensures that permitted units will begin operation before emissions decreases from shutdown of the Gannon boilers fall out of the 5-year contemporaneous period used for the netting analyses. Extensions to the permit will require a new netting analyses and BACT determinations.

4. OTHER STANDARDS AND RESTRICTIONS

Nitrogen Oxides (NOx)

Simple Cycle Operation: Based on the PSD netting analysis, NOx emissions from the project net out of PSD preconstruction review. For the Model PG7241FA gas turbine, General Electric guarantees a NOx emission rate of 9 ppmvd @ 15% oxygen with dry low-NOx combustion control and 42 ppmvd @ 15% oxygen with wet injection. The applicant proposes a NOx emissions standard of 10.5 ppmvd @ 15% oxygen when firing natural gas and 42 ppmvd @ 15% oxygen when firing distillate oil based on a 24-hour average as determined by CEMS. Although not subject to a BACT determination, these emission levels are within the range of BACT determinations for simple cycle units over the last few years. The Department will establish these rates as the NOx emissions standards in the permit. The NSPS Subpart GG NOx standards for these gas turbines are 109.2 ppmvd @ 15% oxygen for firing natural gas and 102.0 ppmvd @ 15% oxygen for firing distillate oil.

Combined Cycle Operation: The previously mentioned settlement agreements require re-powering with natural gas and compliance with a NOx emissions standard of 3.5 ppmvd @ 15% oxygen or less. The current PSD permit also specifies a NOx standard of 3.5 ppmvd @ 15% oxygen (24-hour average) for combined cycle operation of Units 3 and 4. The SCR system will be designed for the primary fuel of natural gas. The original PSD permit (PSD-FL-301) for the re-powering project included restricted amounts of distillate oil. It established "12 ppmvd corrected to 15% oxygen (24-hour average)" as the achievable NOx emissions standard for oil firing after control with the water injection and the SCR system (designed for natural gas). This emissions level is determined to be an achievable NOx standard when firing oil with an SCR system designed for firing natural gas in the 7FA gas turbine. The revised PSD permit will also specify these rates as the NOx emissions standards for combined cycle operation.

The permit requires the SCR system to be designed for an ammonia slip level of 5 ppmvd corrected to 15% oxygen for gas firing. If annual testing shows higher ammonia slip levels, the permit requires the plant to take corrective actions to regain the original design specifications. Only Units 3A and 3B may fire distillate oil. Once converted to combined cycle operation, distillate oil may only be fired as an emergency backup fuel restricted to 700 full load equivalent hours or less. When firing oil and operating an SCR system designed for natural gas, it is estimated that the maximum ammonia slip level would be 9 ppmvd @ 15% oxygen. However, distillate oil can only be fired if natural gas is unavailable (i.e., ruptured gas pipeline, malfunctioning compressor station, etc.). Due to the severely restricted operating scenario, no ammonia slip level will be established for distillate oil firing. Annual testing will be required when firing the primary fuel of natural gas.

Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2) Emissions

Based on the PSD netting analysis, SAM and SO_2 emissions from the project are below the PSD significant emissions rates. Emissions of sulfur dioxide (SO_2) are generated from the fuel sulfur in natural gas and distillate oil. Small amounts of SO_2 may be converted to sulfuric acid mist (SAM). However, natural gas and distillate oil contain little ash, sulfur, or other contaminants. The applicant proposes the following fuel specifications for limiting SAM and SO_2 emissions: pipeline natural gas (≤ 2 grains of sulfur per 100 scf) and distillate oil (≤ 0.05% sulfur by weight) restricted to an equivalent of 700 full load hours of operation. These fuel specifications effectively limit potential SAM and SO_2 emissions and have been specified as BACT for similar gas turbine projects over the last few years for these pollutants. The NSPS Subpart GG SO_2 standard for these gas turbines is the firing of a fuel containing no more than 0.5% sulfur by weight. The proposed fuel specifications will be specified as the standards for these pollutants and will apply during combined cycle and simple cycle operation.

Distillate Oil Firing

Units 3A and 3B will incorporate dual fuel combustors for the firing of distillate oil. The applicant requested 700 full load equivalent hours per year of distillate oil firing for each simple cycle gas turbine. This is equivalent to 9,722,300 gallons of distillate oil per year per gas turbine based on a maximum oil firing rate of 13,889 gph (2015 MMBtu/hour) per unit. Simple cycle Units 3A and 3B will be restricted to this amount of distillate based on a 12-month rolling total.

The EPA-TECO Consent Decree only allows distillate oil firing in a re-powered Gannon Unit as an emergency backup fuel when natural gas is not available. From discussions with EPA, example scenarios include a ruptured natural gas pipeline or the shutdown of a critical compressor station along the pipeline. Based on the EPA-TECO Consent Decree and the applicant's request, when converted to combined cycle operation, Units 3A and 3B may be fired with distillate oil if and only if:

(1) The unit cannot be fired with natural gas;

(2) The unit has not yet been fired with No. 2 fuel oil as a backup fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the unit with such oil; *{Note that these units remain subject to the oil firing limit of 9,722,300 gallons of distillate oil during any consecutive 12-month period (equivalent to 700 full load equivalent hours of operation).}*

(3) The oil to be used in the unit has a sulfur content of less than 0.05 percent (by weight);

(4) Tampa Electric uses all emission control equipment for that unit when it is fired with such oil to the maximum extent possible; and

(5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

When converted to combined cycle operation, SCR systems will be installed on Units 3A and3B. As previously discussed, the revised PSD permit will include a NOx standard of "12 ppmvd corrected to 15% oxygen (24-hour average)" for distillate oil firing in combined cycle Units 3A and 3B after control with the water injection and an SCR system (designed for natural gas). This will be the achievable NOx standard alluded to in paragraphs (4) and (5) of the above EPA restrictions on oil firing. This NOx standard as well as the EPA restrictions on oil firing will be included in the draft permit for combined cycle operation of Units 3A and 3B when firing oil.

5. EXCESS EMISSIONS

The PSD permit was recently revised (PSD-FL-301B) to clarify the alternate standards and CEMS data exclusion requirements for combined cycle operation. For Units 3 and 4, the same conditions will apply regarding opacity during startup/shutdown, requirements for low load operation, and CEMS data exclusion due to startup, shutdown, malfunction, DLN tuning, compressor blade drying, and over speed trip testing. Units 3A and 3B during simple cycle operation will also be regulated by the Condition 17c(2), which states:

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

6. AIR QUALITY IMPACT ANALYSIS

The project triggers a PSD air quality modeling analysis for CO and VOC emissions. With regard to VOC emissions, the applicant estimates that the simple cycle project will result in a net increase of 62 tons per year and the Department estimates the net increase to be 68 tons per year for the simple cycle project and 88 tons per year for the combined cycle project. VOC emissions are regulated as a precursor to the pollutant ozone. Table 212.400-3, F.A.C. defines a de minimis ambient impact level for each pollutant below which preconstruction monitoring is not required. As stated in this table, "No de minimis air quality level is provided for ozone. However, any net increase of 100 tons per year or more of volatile organic compounds subject to preconstruction review would be required to perform an ambient impact analysis, including the gathering of ambient air quality data." Because the estimated VOC emissions increase is less than the de minimis level of 100 tons per year, no preconstruction monitoring or ambient impact analysis is required for VOC emissions.

The applicant did perform an analysis for CO emissions using the refined ISCST3 model that conservatively included eleven gas turbines operating under nine separate scenarios including distillate oil. The model predicted a maximum 1-hour CO emissions impact of 696.6 $\mu g/m^3$ and a maximum 8-hour CO emissions impact of 224.8 $\mu g/m^3$. The predicted 8-hour maximum CO concentration is below the 8-hour de minimis ambient impact for CO emissions of 575 $\mu g/m^3$ as listed in Table 212.400-3, F.A.C. Therefore, no preconstruction monitoring is required for CO emissions. In addition, the predicted maximum 1-hour and 8-hour CO emission impacts are below the PSD Class II significant impact levels of 2000 $\mu g/m^3$ and 500 $\mu g/m^3$, respectively. Therefore, impacts from the project are not considered significant and no further modeling is required.

The Department requested the applicant to perform a modeling analysis for CO, NO_2, PM_{10}, and SO_2 emissions from the re-powered plant for comparison with the state and federal ambient air quality standards (AAQS). Again, the applicant used the refined ISCST3 model and conservatively included eleven gas turbines operating under nine separate scenarios. The following table compares the predicted emissions impacts to the state and federal AAQS.

Table 6A. Comparison of Project Impacts to AAQS

Pollutant	Avg. Period $\mu g/m^3$	Project Impact	Case No.	Year	Florida		Federal	
					AAQS	% of AAQS	NAAQS	% of NAAQS
SO_2	HSH, 3-hour	217.1	1	1996	1300	16.7	1300	16.7
	HSH, 24-hour	56.4	3	1996	260	21.7	365	15.4
	Annual	2.51	3	1996	60	4.2	80	3.1
NO_2	Annual	5.14	3	1996	100	5.1	100	5.1
PM_{10}	HSH, 24-hour	52.6	12	1995	150	35.1	150	35.1
	Annual	3.58	12	1996	50	7.2	50	7.2
CO	HSH, 1-hour	696.6	9	1995	40,000	1.7	40,000	1.7
	HSH, 8-hour	224.8	9	1992	10,000	2.2	10,000	2.2

As shown in the above table, predicted emission impacts are well below the state and federal ambient air quality standards. For complete details regarding the modeling analysis, please refer to the application.

Analysis of Additional Impacts from Growth on Soils, Vegetation, and Wildlife

Impact on Soils, Vegetation, and Wildlife

The following is an excerpt from the application regarding the additional impacts analysis.

> "The project is located in an industrial area that has not experienced significant general growth since August 7, 1977. The air quality impacts of any major industrial project in the area of the Bayside Power Station would have been subject to a detailed regulatory agency assessment under the PSD permitting program.
>
> Impacts associated with construction of the proposed project will be minor. While not readily quantifiable, the temporary increase in vehicular miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.
>
> Bayside Unit 3 is being constructed to meet general electric power demands and, therefore, no significant secondary growth effects due to operation of the simple cycle unit are anticipated. When operational, Unit 3 is projected to generate less than five new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas and distillate oil demand due to operation of the simple cycle units will have no major impact on local markets. No significant air quality impacts due to associated industrial/commercial growth are expected."

Very low emissions are expected from the simple cycle gas turbines in comparison with conventional power plants generating equivalent amounts of electricity. The "re-powering project" for combined cycle Bayside Units 1 through 4 will result in decreases of more than 20,000 tons per year of NOx and more than 50,000 tons per year of SO_2. Emissions of acid rain and ozone precursors will be very low. The predicted maximum ground-level carbon monoxide concentrations from the proposed project will be considerably less than the respective significant impact levels. In addition, the predicted concentrations of CO, NO_2, PM/PM_{10}, and SO_2 are well below the state and federal 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. There will be little growth associated with this project because it involves a relatively small footprint on an existing plant site.

7. 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 impact analysis, and the conditions specified in the draft permit. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Deborah Nelson is the staff meteorologist responsible for reviewing the ambient air quality analysis provided by the applicant. Additional details regarding this review 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.

ATTACHMENT A
SIMPLE CYCLE NETTING ANALYSIS - PSD BACT REVIEW
Bayside Power Station (PSD-FL-301C)

Bayside Simple Cycle Units 3A and 3B
Comparison of Future Potential to Adjusted Past Actual Emissions
Used to Determine Pollutants Subject to PSD for BACT Analysis

Emissions Increases and Decreases	CO	NOx	PM/PM10	SO_2	VOC
Past Actuals					
Shutdown Gannon Units 5 and 6	354	1,808	181	1,843	28
Future Potentials	1,174	1,489	431	464	116
Bayside CC Units 1 and 2	880	708	346	316	86
Bayside SC Units 3A and 3B	294	781	85	148	30

Net Emissions Increases	820	-319	250	-1,379	88
PSD Significant Emission Rate	100	40	15/25	40	40
Subject to BACT Determination?	**Yes**	No	**Yes**	No	**Yes**

NOTES:

a. *Adjusted past actual emissions are defined as the emissions that would have been emitted if the units had installed BACT-level controls. In this way, no credit is given for the alleged NSR violations.*

b. *Only emissions decreases from Gannon Units that will be re-powered have been used in the netting analysis. This is consistent with the amended EPA/TECO Consent Decree.*

ATTACHMENT A
SIMPLE CYCLE NETTING ANALYSIS - PSD MODELING REVIEW
Bayside Power Station (PSD-FL-301C)

Bayside Simple Cycle Units 3A and 3B
Comparison of Future Potential to Past Actual Emissions
Used to Determine Pollutants Subject to PSD for Modeling Review

Emissions Increases and Decreases	**CO**	**NOx**	**PM/PM10**	**SO_2**	**VOC**
Past Actuals					
Shutdown Gannon Units	354	15,681	1,146	36,855	28
Future Potentials	1,174	1,489	431	464	116
Bayside Units 1 and 2	880	708	346	316	86
Bayside Unit 3 - Simple Cycle Project	294	781	85	148	30

Net Emissions Increases	820	-14,192	-715	-36,391	88
PSD Significant Emission Rate	100	40	15/25	40	40
Subject to PSD Preconstruction Review?	**Yes**	No	No	No	**Yes**

NOTES:

a. *This analysis is based on full past actual emissions from these units. It is NOT based on adjusted past actual emissions (with BACT-level controls). Instead, it is based on the full actual reductions realized from the shutdown coal-fired Gannon boilers. This is consistent with the review for the original project.*

ATTACHMENT B
COMBINED CYCLE NETTING ANALYSIS - PSD BACT REVIEW
Bayside Power Station (PSD-FL-301C)

Project to Add Bayside Combined Cycle Units 3 and 4
Comparison of Future Potential to Adjusted Past Actual Emissions
Used to Determine Pollutants Subject to PSD for BACT Analysis

Emissions Increases and Decreases	**CO**	**NOx**	**PM/PM_{10}**	**SO_2**	**VOC**
Adjusted Past Actuals					
Shutdown Gannon Units 3 - 6	577	2,718	272	2,641	77
Future Potentials	1,468	2,270	516	611	145
Bayside CC Units 1 and 2	880	708	346	316	86
Bayside CC Units 3 and 4	588	1,562	170	295	59

Net Emissions Increases	891	-448	244	-2,030	68
PSD Significant Emission Rate	100	40	15/25	40	40
Subject to BACT Determination?	**Yes**	No	**Yes**	No	**Yes**

NOTES:

a. *This project will re-power existing steam turbine-electrical generators from Gannon Units 3 and 4.*

b. *Adjusted past actual emissions are defined as the emissions that would have been emitted if the units had installed BACT-level controls. In this way, no credit is given for the alleged NSR violations.*

c. *Only emissions decreases from Gannon Units that will be re-powered have been used in the netting analysis. This is consistent with the amended EPA/TECO Consent Decree.*

ATTACHMENT B
COMBINED CYCLE NETTING ANALYSIS - PSD MODELING REVIEW
Bayside Power Station (PSD-FL-301C)

Project to Add Bayside Combined Cycle Units 3 and 4
Comparison of Future Potential to Past Actual Emissions
Used to Determine Pollutants Subject to PSD for Modeling Analysis

Emissions Increases and Decreases	**CO**	**NOx**	**PM/PM10**	**SO2**	**VOC**
Past Actuals					
Shutdown Gannon Units 3 - 6	577	24,237	1,563	52,824	77
Future Potentials	1,468	2,270	516	611	145
Bayside CC Units 1 and 2	880	708	346	316	86
Bayside CC Units 3 and 4	588	1,562	170	295	59

Net Emissions Increases	891	-21,967	-1,047	-52,213	68
PSD Significant Emission Rate	100	40	15/25	40	40
Subject to PSD Modeling Analysis?	**Yes**	No	No	No	**Yes**

NOTES:

a. *This analysis is based on full past actual emissions from these units. It is NOT based on adjusted past actual emissions (with BACT-level controls). Instead, it is based on the full actual reductions realized from the shutdown coal-fired Gannon boilers. This is consistent with the review for the original project.*

DRAFT PERMIT

PERMITTEE:

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

Authorized Representative:
Wade A. Maye, General Manager

H. L. Culbreath Bayside Power Station
Air Permit No. PSD-FL-301C
Project No. 0570040-019-AC
Expires: December 31, 2007

PROJECT

The Tampa Electric Company operates the H. L. Culbreath Bayside Power Station in Tampa at 3602 Port Sutton Road in Hillsborough County, Florida. The electrical power plant (SIC No. 4911) was formerly known as the F. J. Gannon Station, but was re-powered with combined cycle gas turbines firing natural gas. This permit revision authorizes: a phase of simple cycle operation for Bayside Units 3A and 3B; distillate oil as a restricted alternate fuel for Bayside Units 3A and 3B during simple cycle operation; distillate oil as an emergency backup fuel for Bayside Units 3A and 3B once converted to combined cycle operation; and an extension of the expiration date to allow construction of Bayside Units 3 and 4.

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 and perform the work 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/TECO Consent Final Judgment or the EPA/TECO Consent Decree.

Michael G. Cooke, Director
Division of Air Resource Management

Effective Date

FACILITY DESCRIPTION

Upon completing construction of all Bayside Units and retiring all coal-fired Gannon units, the H. L. Culbreath Bayside Power Station will have an electrical production capacity of 2845 MW based on the following nominal capacities: Bayside Unit 1 (746 MW), Bayside Unit 2 (1090 MW), Bayside Unit 3 (501 MW), and Bayside Unit 4 (508 MW). Note that the final design may not fully utilize the nameplate capacities of the existing steam-electrical turbines. The following table summarizes the emission units regulated by this air construction permit.

EU No.	Status	Emission Unit Description
001 [a]	Retired	Gannon Unit 1 – coal fired boiler (125 MW steam electrical generator)
002 [a]	Retired	Gannon Unit 2 – coal fired boiler (125 MW steam electrical generator)
003 [a]	Retired	Gannon Unit 3 – coal fired boiler (163 MW steam electrical generator)
004 [a]	Retired	Gannon Unit 4 – coal fired boiler (170 MW steam electrical generator)
005 [a]	Retired	Gannon Unit 5 – coal fired boiler (239 MW steam electrical generator)
006 [a]	Retired	Gannon Unit 6 – coal fired boiler (414 MW steam electrical generator)
008 [a]	Functional	Gannon Coal Yard
020 [b]	Operating	Bayside Unit 1A – 169 MW combined cycle gas turbine
021 [b]	Operating	Bayside Unit 1B – 169 MW combined cycle gas turbine
022 [b]	Operating	Bayside Unit 1C – 169 MW combined cycle gas turbine
023 [c]	Operating	Bayside Unit 2A – 169 MW combined cycle gas turbine
024 [c]	Operating	Bayside Unit 2B – 169 MW combined cycle gas turbine
025 [c]	Operating	Bayside Unit 2C – 169 MW combined cycle gas turbine
026 [c]	Operating	Bayside Unit 2D – 169 MW combined cycle gas turbine
027 [d]	Proposed	Bayside Unit 3A – 169 MW combined cycle gas turbine
028 [d]	Proposed	Bayside Unit 3B – 169 MW combined cycle gas turbine
029 [e]	Proposed	Bayside Unit 4A – 169 MW combined cycle gas turbine
030 [e]	Proposed	Bayside Unit 4B – 169 MW combined cycle gas turbine

Notes

a. The coal fired Gannon boilers were permanently retired on the following dates: Unit 1 (04/16/03); Unit 2 (04/15/03); Unit 3 (11/01/03); Unit 4 (10/12/03); Unit 5 (01/30/03); and Unit 6 (09/30/03). The Gannon coal yard (EU 008) remains functional.

b. Bayside Unit 1 is constructed and began commercial operation on March 16, 2003. The three gas turbines comprising Bayside Unit 1 re-power the 239 MW steam electrical generator from Gannon Unit 5.

c. Bayside Unit 2 is constructed and began commercial operation on November 19, 2003. The four gas turbines comprising Bayside Unit 2 re-power the 414 MW steam electrical generator from Gannon Unit 6.

d. The two gas turbines comprising Bayside Unit 3 will re-power the 163 MW steam electrical generator from Gannon Unit 3. This revised permit authorizes a phase of simple cycle operation for these units.

e. The two gas turbines comprising Bayside Unit 4 will re-power the 170 MW steam electrical generator from Gannon Unit 4.

REGULATORY CLASSIFICATION

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

Title IV: All Bayside gas turbines are subject to the Phase II Acid Rain requirements. All Gannon boilers have been permanently shutdown and are considered "retired units" in accordance with the Acid Rain provisions.

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

Site Certification: The facility is not subject to any specific power plant site certification requirements.

PSD: The facility is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

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

NESHAP: The re-powered facility is not a major source of hazardous air pollutants; therefore the National Emissions Standards for Hazardous Air Pollutants in Subpart YYYY of 40 CFR 63 do not apply to the gas turbines.

RELEVANT DOCUMENTS

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

- DEP/TECO Consent Final Judgment signed on December 7, 1999.
- EPA/TECO Consent Decree entered on October 5, 2000.
- Original Permit No. PSD-FL-301 issued on March 30, 2001 including the application and related correspondence. This permit (Project No. 0570040-013-AC) authorized construction of Bayside Units 1 and 2.
- Revised Permit No. PSD-FL-301A issued on January 8, 2002 including the application and related correspondence. This permit (Project No. 0570040-015-AC) included the construction of Bayside Units 3 and 4.
- Revised Permit No. PSD-FL-301B issued on November 9, 2004 including the application and related correspondence. This permit (Project No. 0570040-021-AC) revised Condition 17 related to monitoring data exclusions.
- Application No. 0570040-019-AC (PSD-FL-301C) received on July 22, 2003 and related correspondence to make it complete.

APPENDICES

The following Appendices are attached as part of this permit.

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

ADMINISTRATIVE REQUIREMENTS

1. Effective Date: The effective date of this permit is specified on the placard page (page 1).
2. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit shall 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. Copies shall also be provided to each Compliance Authority.
3. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications shall be submitted to the Air Management Division of the Environmental Protection Commission of Hillsborough County at 1410 North 21 Street, Tampa, FL 33605. Copies of all such documents shall 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.
4. 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.
5. General Conditions: The owner and operator are subject to, and shall operate under, the attached General Conditions listed in *Appendix GC* of this permit. [Rule 62-4.160, F.A.C.]
6. 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.]
7. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months of the effective date of this permit, 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/TECO Consent Final Judgment or the EPA/TECO Consent Decree. [40 CFR 52.21(r)(2)]
8. 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/TECO Consent Final Judgment or the EPA/TECO Consent Decree. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C.]
9. 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 will 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 51.166(j)(4)]
10. 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.]
11. 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 62-210.200 (Definitions) and 62-210.300(1), F.A.C.]

12. 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]

13. 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 with copies to the 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 the 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.; 40 CFR 60.7; 40 CFR 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 Compliance Authority, 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 Compliance Authority. [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 Compliance Authority 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 the 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 Compliance Authority 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.]

This section of the permit addresses the following emissions units.

Emissions Units 020 – 026: Bayside Units 1 and 2

Description: Each emissions unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack 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 exclusive fuel.

Heat Input: At a compressor inlet air temperature of 59° F and firing 1842 MMBtu (HHV) per hour of natural gas, each unit produces a nominal 169 MW of shaft-driven electricity. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,000 acfm at 220° F.

Generating Capacity: The following table summarizes the electrical generating capacity for each combination of combined cycle gas turbines and steam-electrical turbines.

EU No.	Bayside GT Unit	GT MW, Shaft	Existing Gannon ST	MW, ST	Total
020	1A	169 MW	No. 5	239	746
021	1B	169 MW			
022	1C	169 MW			
023	2A	169 MW	No. 6	414	1090
024	2B	169 MW			
025	2C	169 MW			
026	2D	169 MW			
Totals	7 GTs	1183 MW	2 STs	653	1836

Note: GT means gas turbine. The nameplate generating capacity is shown for the steam-electrical turbines (ST). The final design may not fully utilize the nameplate generating capacity.

Controls: The efficient combustion of natural gas at high temperatures minimizes the emissions of CO, PM/PM_{10}, and VOC. Firing natural gas as the only authorized fuel minimizes emissions of SAM and SO_2 because natural gas contains only small amounts of sulfur. A selective catalytic reduction (SCR) system combined with dry low-NOx (DLN) combustion technology reduces NOx emissions.

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

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. 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

3. Construction: Bayside Unit 1 is constructed and began commercial operation on March 16, 2003. Bayside Unit 2 is constructed and began commercial operation on November 19, 2003. The revised permit (PSD-FL-301C) does not authorize any additional construction for these units. [Application; Rule 62-212.400(BACT), F.A.C.]

4. 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 169 MW of shaft-driven 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]

5. Heat Recovery Steam Generators (HRSG): Each gas turbine system includes an unfired HRSG with three levels of steam conditions (high pressure, intermediate pressure, and low pressure). [Design]

6. Automated Control System: The permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ Mark VI automated control system (or better) for each gas turbine. 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 and shutdown. [Design; 62-212.400(BACT), F.A.C.]

7. DLN Combustion Technology: The permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to provide efficient lean premix combustion. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Design; Rule 62-212.400(BACT), F.A.C.]

8. SCR System: The permittee shall install, tune, operate and maintain a selective catalytic reduction (SCR) system to reduce NOx emissions from each combined cycle gas turbine. The SCR system shall consist of an ammonia injection grid, catalyst, ammonia storage, a monitoring and control system, electrical system, piping, and other ancillary equipment. The SCR system shall be designed to reduce NOx emissions while minimizing ammonia slip within the permitted levels. [DEP/TECO Consent Final Judgment; EPA/TECO Consent Decree; Rule 62-4.070(3), F.A.C.]

9. Evaporative Inlet Air-Cooling System: Each gas turbine system includes 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 increases power production with additional fuel combustion. *{Permitting Note: The installed equipment includes 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.}* [Applicant Request; Design]

PERFORMANCE RESTRICTIONS

10. Permitted Capacity: The maximum heat input rate to each gas turbine shall not exceed 1842 MMBtu per hour while producing approximately 169 MW (shaft). The maximum heat input rate is based on a

compressor inlet air temperature of 59° F, the higher heating value (HHV) of natural gas and expected performance levels. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

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

12. Restricted Operation: The hours of operation for each gas turbine are not limited (8760 hours per year). [Application; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

13. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods to minimize emissions during startup and shutdown. [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.}

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

    a. **Ammonia Slip**: Subject to the requirements of Condition 22 in this subsection, each SCR system shall be designed and operated for an ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. [Rule 62-4.070(3), F.A.C.]

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

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

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

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

f. **Visible Emissions**: Visible emissions shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. Except as allowed by Condition 17 of this subsection, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]

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

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

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

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

Each 24-hour block average shall start at midnight each operating day and shall be calculated from 24 consecutive 1-hour averages. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of the available valid 1-hour averages. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

STARTUP, SHUTDOWN, MALFUNCTION, AND LOW LOAD OPERATION

16. <u>Excess Emissions Prohibited</u>: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in the compliance averages determined from the CO and NOx CEMS data. [Rule 62-210.700(4), F.A.C.]

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

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

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

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

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

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

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

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

(5) *DLN Tuning*: "DLN Tuning" means operating the gas turbine at intermittent loads throughout the full load range in order to adjust and tune the dry low-NOx (DLN) combustion system. DLN

tuning shall be conducted in accordance with manufacturer' recommendations. Emissions data collected during DLN tuning may be excluded from the 24-hour block compliance averages. *{Permitting Note: For example, a major tuning session would occur after combustor change-out.}*

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

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

To the extent practicable, the permittee shall minimize the amount and duration of emissions during periods of startup, shutdown, malfunction, DLN tuning, compressor blade drying, and over speed trip testing. If a CEMS reports emissions in excess of an emissions standard (24-hour block), the permittee shall notify the Compliance Authority within one working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Compliance Authority may request a written summary report of the incident. All emissions data allowed for exclusion shall be summarized in the Semiannual CEMS Report required in Condition 25 of this subsection.

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

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

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

EMISSIONS PERFORMANCE TESTING

18. Operating Rate During Testing: Emissions performance testing shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

19. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

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

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

20. Initial Compliance Tests: Each gas turbine shall be tested to demonstrate compliance with the emission standards for CO, NOx, visible emissions and ammonia slip. The tests shall 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 gas turbine. Tests for CO and NOx shall be conducted concurrently. Certified CEMS data may be used to demonstrate compliance with the initial CO and NOx standards. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.335]

21. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for ammonia slip and visible emissions. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. *{Permitting Note: Continuous compliance with the CO and NOx standards will be demonstrated with certified CEMS data.}* [Rules 62-212.400(BACT) and 62-297.310(7)(a)4, F.A.C.]

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

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

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

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

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

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

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

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

    c. **Data Exclusion**. CO, CO_2, and NOx emissions data shall be recorded by the CEMS at all times including episodes of startup, shutdown, malfunction, and tuning. CO and NOx emissions data recorded during such episodes may be excluded from the 24-hour block compliance averages in accordance with the requirements of Condition 17 of this subsection. All periods of data excluded due to startup, shutdown or malfunction shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited. Excluded emissions shall be summarized in the required semiannual report.

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

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

f. **Monitor Availability**. Monitor availability shall not be less than 95% in any calendar quarter. The report required in Condition 23e above shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Compliance Authority with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

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

[Rules 62-4.070(3), 62-210.700(5), and 62-212.400(BACT), F.A.C.]

24. <u>Ammonia Monitoring Requirements</u>: The permittee shall install, calibrate, maintain and operate, in accordance with the manufacturer's specifications, an ammonia flow meter to measure and record the ammonia injection rate through each SCR system. The permittee shall document the general range of ammonia flow rates required to meet emissions limitations over the range of gas turbine load conditions allowed in this permit by comparing NOx emissions recorded by the NOx monitor with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the gas turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

25. Semiannual CEMS Report: In addition to the reports required pursuant to 40 CFR 60.7, the permittee shall submit semiannual reports for each gas turbine summarizing the CEMS data and equipment. For each calendar quarter, the report shall include: the 24-hour block compliance averages for each day of operation; the number of 1-hour emission averages excluded from each 24-hour compliance average; the emissions rate of the excluded monitoring data; the reason for excluding monitoring data; the hours of missing data due to monitor downtime; the reason for any monitor downtime; unusual maintenance or repair of the CEMS; and a summary of any RATA tests performed. Based on operational data, the permittee shall also update the general range of ammonia flow rates required to meet NOx emissions limitations over the range of gas turbine load conditions. A report covering operations from January through June shall be submitted by July 30th of each year. A report covering operations from July through December shall be submitted by January 30th of each year. The report due dates may be modified by the Title V permit. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

26. Monitoring of Operations: To demonstrate compliance with the gas turbine capacity requirements, the permittee shall monitor and record the operating rate of each gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEMS required above, or by monitoring daily rates of consumption and heat content of natural gas in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

B. GANNON UNITS

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

EU ID	Status	Emission Unit Description
001	Retired	Gannon Unit 1 – coal fired boiler (125 MW steam electrical generator)
002	Retired	Gannon Unit 2 – coal fired boiler (125 MW steam electrical generator)
003	Retired	Gannon Unit 3 – coal fired boiler (163 MW steam electrical generator)
004	Retired	Gannon Unit 4 – coal fired boiler (170 MW steam electrical generator)
005	Retired	Gannon Unit 5 – coal fired boiler (239 MW steam electrical generator)
006	Retired	Gannon Unit 6 – coal fired boiler (414 MW steam electrical generator)
008	Functional	Gannon Coal Yard

SHUTDOWN REQUIREMENTS

1. Shutdown of Coal-Fired Gannon Units: Pursuant to this federally enforceable PSD air construction permit, the coal-fired boilers for Gannon Units 1 through 6 (EUs 001 – 006) shall be permanently shut down no later than December 31, 2004. Based on the "Retired Unit Exemption" form submitted to the Department, all of these units have been permanently shut down and the dates of permanent retirement are: Unit 1 (04/16/03); Unit 2 (04/15/03); Unit 3 (11/01/03); Unit 4 (10/12/03); Unit 5 (01/30/03); and Unit 6 (09/30/03). [Permit No. PSD-FL-301, as revised; EPA/TECO Consent Decree; DEP Form No. 62-210.900(1)(a)3, F.A.C.]

2. Coal Yard: The Gannon coal yard (EU 008) remains operable. Coal throughput for this facility shall not exceed 2.85 million tons in any 12 consecutive months. *{Permitting Note: TECO is exploring possible long term plans to use the existing coal handling capabilities as a coal storage and distribution terminal. Additional permits may be required.}* [Rules 62-4.160(2), 62-210.200 (PTE), and 62-212.400(2)(a)2, F.A.C.; Permit No. 0570040-006-AC]

3. 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/TECO Consent Decree]

4. Revisions or Extensions: The provisions of this section shall not be extended or revised the without the prior approval of the U.S. EPA. [EPA/TECO Consent Decree]

This section of the permit addresses the following emissions units.

Emissions Units 027 – 030: Bayside Units 3 and 4

Description: Each emissions unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a combined cycle exhaust stack (150 feet tall and 19.0 feet in diameter), a simple cycle exhaust stack for Units 3A and 3B (114 feet tall and 18.8 feet in diameter), and associated support equipment. Each unit fires natural gas and Units 3A and 3B may fire distillate oil as a restricted alternate fuel (simple cycle) or as an emergency backup fuel (combined cycle).

Permitted Capacity: At a compressor inlet air temperature of 59° F, the maximum heat input rate to each gas turbine is 1842 MMBtu (HHV) per hour of natural gas. At a compressor inlet air temperature of 59° F, the maximum heat input rate to each Unit 3A or 3B gas turbine is 2015 MMBtu (HHV) per hour of distillate oil.

Stack Conditions: When Units 3 and 4 are operating as combined cycle units at full load, exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,000 acfm at 220° F for gas firing and 1,160,000 acfm at 275° F for oil firing (Unit 3 only). When Units 3A or 3 B are operating as simple cycle units at full load, exhaust gases exit the stack with a volumetric flow rate of approximately 2,394,000 acfm at 1120° F for gas firing and 2,469,000 acfm at 1100° F for oil firing.

Generating Capacity: The following table summarizes the electrical generating capacity for each combination of combined cycle gas turbines and steam-electrical turbines.

EU No.	Bayside GT Unit	GT MW, Shaft	Existing Gannon ST	MW, ST	Total
027	3A	169 MW	No. 3	163	501
028	3B	169 MW			
029	4A	169 MW	No. 4	170	508
030	4B	169 MW			
Totals	4 GTs	676 MW	2 STs	333	1009

Note: GT means gas turbine. The nameplate generating capacity is shown for the steam-electrical turbines (ST). The final design may not fully utilize the nameplate generating capacity.

Controls: The efficient combustion of clean fuels minimizes the emissions of CO, PM/PM_{10}, and VOC. The firing of very low sulfur fuels minimizes potential emissions of SAM and SO_2. Dry low-NOx (DLN) combustion technology when firing natural gas and water injection when firing distillate oil inhibit NOx emissions. When operating in the combined cycle mode, a selective catalytic reduction (SCR) system further reduces NOx emissions.

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

APPLICABLE STANDARDS AND REGULATIONS

1. <u>BACT Determinations</u>: 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. <u>NSPS Requirements</u>: Each gas turbine shall comply with Subpart GG in 40 CFR 60, the New Source Performance Standards (NSPS) for Stationary Gas Turbines, as specified in Appendix GG of this permit. In addition, each gas turbine shall comply with the applicable requirements of Subpart A in 40 CFR 60, the

NSPS 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). [40 CFR 60; Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT

3. Construction: Bayside Unit 3 is scheduled to commence construction in May of 2005 and complete construction in 2006. Units 3A and 3B may be installed and operated as simple cycle units and later converted to combined cycle units. Unit 4 will be added as a combined cycle unit. The permittee shall inform the Department and Compliance Authority of any substantial changes to the construction schedule including conversion of Units 3A and 3B to combined cycle operation. Pursuant to 40 CFR 52.21(r)(2):
   a. Construction of Bayside Units 3A and 3B shall commence within 18 months after permit issuance. Otherwise, authorization to construct shall become invalid.
   b. Conversion of Units 3A and 3B to combined cycle operation shall be complete before this permit expires. Otherwise, the Department will require revalidation of the BACT determinations and a new netting analysis for any requests to extend the permit.
   c. Construction of combined cycle Unit 4 shall be complete before this permit expires. Otherwise, the Department will require revalidation of the BACT determinations and a new netting analysis for any requests to extend the permit.
   d. Each combined cycle unit shall include an SCR system to reduce NOx emissions.

   [Application; Rule 62-212.400(BACT), F.A.C.]
4. Gas Turbines: The permittee is authorized to install, tune, operate and maintain four new General Electric Model PG7241(FA) gas turbines with electrical generator sets, each designed to produce a nominal 169 MW of shaft-driven electrical power. Each unit shall be designed for eventual operation 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 combined cycle exhaust stack (150 feet tall and 19.0 feet in diameter), and associated support equipment. Bayside Units 3A and 3B may be installed as simple cycle units and later converted to combined cycle units. Units 3A and 3B will each have a simple cycle exhaust (114 feet tall and 18.8 feet in diameter). [Applicant Request; Design]
5. Heat Recovery Steam Generators (HRSG): Each gas turbine system shall be designed to include an unfired HRSG with three levels of steam conditions (high pressure, intermediate pressure, and low pressure). [Design]
6. Automated Control System: The permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ Mark VI automated control system (or better) for each gas turbine. 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 and shutdown. [Design; 62-212.400(BACT), F.A.C.]
7. Combustion Controls
   a. *DLN Combustion Technology*: Each gas turbine shall incorporate the General Electric dry low-NOx combustion system (DLN 2.6 or better) to provide efficient lean premix combustion. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to reduce CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations to maintain CO and NOx emissions at the optimum levels. [Design; Rule 62-212.400(BACT), F.A.C.]

b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system on Units 3A and 3B to reduce NOx emissions from each gas turbine when firing distillate oil. The water injection system shall be tuned to achieve the permitted levels for CO and NOx emissions during simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to achieve the NOx emission standard for oil firing during simple cycle operation on a 1-hour basis. [Design; Rule 62-212.400(BACT), F.A.C.]

8. SCR System: The permittee shall install, tune, operate and maintain a selective catalytic reduction (SCR) system to reduce NOx emissions from each combined cycle gas turbine. The SCR system shall consist of an ammonia injection grid, catalyst, ammonia storage, a monitoring and control system, electrical system, piping, and other ancillary equipment. The SCR system shall be designed to reduce NOx emissions while minimizing ammonia slip within the permitted levels for gas firing. [DEP/TECO Consent Final Judgment; EPA/TECO Consent Decree; Rule 62-4.070(3), F.A.C.]

9. Evaporative Inlet Air-Cooling System: Each gas turbine system includes 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 increases power production with additional fuel combustion. *{Permitting Note: The proposed equipment includes 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.}* [Applicant Request; Design]

PERFORMANCE RESTRICTIONS

10. Permitted Capacity: At a compressor inlet air temperature of 59° F, the maximum heat input rate to each gas turbine is 1842 MMBtu (HHV) per hour of natural gas. At a compressor inlet air temperature of 59° F, the maximum heat input rate to each Unit 3A and 3B gas turbine is 2015 MMBtu (HHV) per hour of distillate oil. The maximum heat input rates are based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel and the expected performance levels. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

11. Allowable Fuels: The gas turbines shall fire only the following fuels.

a. *Natural Gas*: Each gas turbine shall fire pipeline natural gas with a fuel sulfur content of no more than 2 grains per 100 SCF of natural gas based on a 12-month rolling average. Compliance shall be demonstrated each month by compiling the daily fuel sulfur analyses provided by the pipeline vendor. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods. [Design; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.; DEP/TECO Consent Final Judgment; EPA/TECO Consent Decree]

b. *Distillate Oil – Units 3A and 3B*: As a restricted alternate fuel, Units 3A and 3B may fire new No. 2 distillate oil with a maximum fuel sulfur content of no more than 0.05% sulfur by weight. Each gas turbine shall fire no more than 9,722,300 gallons of distillate oil during any consecutive 12-month period (equivalent to 700 full load equivalent hours of operation). Initial compliance with the fuel 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. [Design; Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

c. *Distillate Oil – Units 3A and 3B, Combined Cycle Operation Only*: Once converted to combined cycle operation, Units 3A and 3B may be fired with new No. 2 distillate oil if and only if:

(1) The unit cannot be fired with natural gas;

(2) The Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil;

(3) The oil to be used in the unit has a sulfur content of less than 0.05 percent (by weight);

(4) Tampa Electric uses all emission control equipment for that unit when it is fired with such oil to the maximum extent possible; and

(5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

These provisions shall not be revised without prior approval from EPA. Units 3A and 3B remain subject to the restriction on firing distillate oil specified in Condition 11b. [EPA/TECO Consent Decree]

12. Restricted Operation: The hours of operation for each gas turbine are not limited (8760 hours per year). [Application; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

13. Operating Procedures: The Best Available Control Technology (BACT) determinations for CO, PM/PM_{10}, and VOC emissions established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods to minimize emissions during startup and shutdown. [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.}

14. Emissions Standards - Performance Tests: The gas turbines shall not exceed the following standards as determined by the emissions performance tests conducted at permitted capacity.

Pollutant	Emission Standards – Performance Tests	Test Method
	Simple Cycle Operation – Units 3A and 3B Only	
Carbon Monoxide (CO)	≤ 28.7 pounds per hour and 7.8 ppmvd corrected to 15% oxygen (gas) ≤ 40.5 pounds per hour and 9.0 ppmvd corrected to 15% oxygen (oil)	EPA Method 10 3 test runs
Nitrogen Oxides (NOx)	≤ 69.1 pounds per hour and 10.5 ppmvd corrected to 15% oxygen (gas) ≤ 320.3 pounds per hour and 42.0 ppmvd corrected to 15% oxygen (oil)	EPA Method 7E 3 test runs
Visible Emissions	≤ 10% opacity, 6-minute block average (gas/oil)	EPA Method 9 30 minutes

Pollutant	Emission Standards – Performance Tests	Test Method
Combined Cycle Operation – Units 3 and 4		
Ammonia Slip	Subject to the requirements of Condition 22 in this subsection, each SCR system shall be designed and operated for an ammonia slip target of less than 5 ppmvd corrected to 15% oxygen for gas firing.	CTM-027 3 test runs
Carbon Monoxide (CO)	≤ 28.7 pounds per hour and 7.8 ppmvd corrected to 15% oxygen (gas)	EPA Method 10 3 test runs
Nitrogen Oxides (NOx)	≤ 23.1 pounds per hour and 3.5 ppmvd corrected to 15% oxygen (gas)	EPA Method 7E 3 test runs
Visible Emissions	≤ 10% opacity, 6minute block average (gas/oil)	EPA Method 9 30 minutes

a. The mass emission limits are based on full load and a compressor inlet temperature of 59° F.

b. NOx emissions are defined as oxides of nitrogen reported as NO_2.

c. Operating data shall be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

d. The CO and NOx standards represent the initial standards for "new and clean" units. Subsequent compliance shall be demonstrated with data collected by the certified CEMS.

e. The efficient combustion of clean fuels represents the Best Available Control Technology (BACT) requirements for emissions of particulate matter and volatile organic compounds. Compliance with carbon monoxide and visible emissions standards shall serve as continuous indicators of efficient combustion to minimize emissions of these pollutants. Compliance with the fuel sulfur specifications of this permit minimizes potential emissions of sulfuric acid mist and sulfur dioxide. No performance tests are required for these pollutants.

f. Only the CEMS-based CO and NOx emissions standards apply to Units 3A and 3B when firing distillate oil and operating in combined cycle mode because these units can only fire distillate oil as an "emergency backup fuel" when operating in this mode.

[Rules 62-4.070(3), 62-212.400(BACT), and 62-297.310, F.A.C.; DEP/TECO Consent Final Judgment; EPA/TECO Consent Decree; 40 CFR 60.332]

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

Pollutant	CEMS-Based Emission Standards	Method
Simple Cycle Operation – Units 3A and 3B Only		
Carbon Monoxide (CO)	≤ 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average (gas/oil)	CO CEMS
Nitrogen Oxides (NOx)	≤ 10.5 ppmvd corrected to 15% oxygen based on a 24-hour block average (gas) ≤ 42.0 ppmvd corrected to 15% oxygen based on a 24-hour block average (oil)	NOx CEMS
Combined Cycle Operation – Units 3 and 4		
Carbon Monoxide (CO)	≤ 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average (gas/oil)	CO CEMS
Nitrogen Oxides (NOx)	≤ 3.5 ppmvd corrected to 15% oxygen based on a 24-hour block average (gas) ≤ 12.0 ppmvd corrected to 15% oxygen based on a 24-hour block average (oil)	NOx CEMS

Each 24-hour block average shall start at midnight each operating day and shall be calculated from 24 consecutive 1-hour averages. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of the available valid 1-hour averages. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

STARTUP, SHUTDOWN, MALFUNCTION, AND LOW LOAD OPERATION

16. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in the compliance averages determined from the CO and NOx CEMS data. [Rule 62-210.700(4), F.A.C.]

17. Alternate Standards and CEMS Data Exclusion: Bayside Units 3 and 4 shall be subject to the same alternate standards and data exclusion requirements as Bayside Units 1 and 2 (Condition 17, Subsection IIIA). [Design; Rules 62-4.130, 62-210.700(5), and 62-212.400 (BACT), F.A.C.; Permit No. PSD-FL-301, as revised]

EMISSIONS PERFORMANCE TESTING

18. Operating Rate During Testing: Emissions performance testing shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

19. Test Methods: Any required tests shall be performed in accordance with the same reference methods and requirements as specified for Bayside Units 1 and 2 (Condition 19, Subsection IIIA). [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

20. Initial Compliance Tests: To demonstrate initial compliance with the emissions standards, tests shall be conducted on each gas turbine within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each gas turbine. Tests shall be conducted in accordance with the following requirements.

    a. *Simple Cycle Units 3A and 3B*: Each simple cycle gas turbine shall be tested to demonstrate initial compliance with the emissions standards for CO, NOx, and visible emissions in Condition 14 of this subsection when firing natural gas and distillate oil.

    b. *Combined Cycle Units 3 and 4*: Each combined cycle gas turbine shall be tested to demonstrate compliance with the emissions standards for CO, NOx, visible emissions and ammonia slip in Condition 14 of this subsection when firing natural gas. *{Permitting Note: For combined cycle operation of Units 3A and 3B, initial tests when firing distillate oil are not required because this fuel may only be fired as a restricted emergency backup fuel.}*

    Tests for CO and NOx shall be conducted concurrently. Certified CEMS data may be used to demonstrate initial compliance with the CO and NOx emissions standards. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.335]

21. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine is subject to the following testing requirements.

a. *Simple Cycle Units 3A and 3B*: Each simple cycle gas turbine shall be tested annually to demonstrate compliance with the standard for visible emissions in Condition 14 of this subsection when firing natural gas and when firing distillate oil (if the unit fires distillate oil for more than 400 hours during the federal fiscal year).

b. *Combined Cycle Units 3 and 4*: Each combined cycle gas turbine shall be tested to demonstrate compliance with the standards for visible emissions and ammonia slip in Condition 14 of this subsection when firing natural gas. The test results for ammonia slip shall also report the CO and NOx emissions recorded by the CEMS during each test run. Units 3A and 3B shall also be tested for visible emissions if the unit fires distillate oil for more than 400 hours during the federal fiscal year.

{Permitting Note: Continuous compliance with the CO and NOx standards will be demonstrated by data collected from the certified CEMS.} [Rules 62-212.400(BACT) and 62-297.310(7)(a)3 and 4, F.A.C.]

22. Additional Ammonia Slip Testing: Ammonia slip testing shall be performed in accordance with the same requirements as specified for Bayside Units 1 and 2 (Condition 22, Subsection IIIA). [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

23. Continuous Emissions Monitoring Systems: The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) in the exhaust stack of each emissions unit to measure and record emissions of CO and NOx in a manner sufficient to demonstrate compliance with the CEMS emission standards of this permit. The carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. The oxygen content of the flue gas shall be calculated by the CEMS using the CO_2 content of the flue gas and an F-factor that is appropriate for natural gas. Each CEMS shall comply with the same requirements as specified for Bayside Units 1 and 2 (Condition 23, Subsection IIIA). *{Permitting Note: A multi-span monitor may be necessary for Units 3A and 3B due to the higher NOx standards.}* [Rules 62-4.070(3), 62-210.700(5), and 62-212.400(BACT), F.A.C.]

24. Ammonia Monitoring Requirements: The permittee shall install, calibrate, maintain and operate in accordance with the manufacturer's specifications an ammonia flow meter to measure and record the ammonia injection rate through each SCR system. The permittee shall document the general range of ammonia flow rates required to meet emissions limitations over the range of gas turbine load conditions allowed in this permit by comparing NOx emissions recorded by the NOx monitor with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the gas turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

25. Semiannual CEMS Report: For Units 3 and 4, the permittee shall submit semiannual reports for each gas turbine summarizing the CEMS data and equipment in accordance with the requirements specified for Bayside Units 1 and 2 (Condition 25, Subsection IIIA). [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

26. Monitoring of Operations: To demonstrate compliance with the gas turbine capacity requirements, the permittee shall monitor and record the operating rate of each gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEMS required above, or by monitoring daily rates of consumption and heat content of natural gas in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

CEMS	-	Continuous Emissions Monitoring System
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

SUMMARY OF BACT DETERMINATIONS AND EMISSIONS STANDARDS

Background Discussion

The Tampa Electric Company operates the H. L. Culbreath Bayside Power Station in Tampa (Hillsborough County), an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. The electrical power plant was formerly known as the F. J. Gannon Station, but was re-powered with combined cycle gas turbines firing natural gas. The actual and potential annual emissions of several pollutants from the existing facility are greater than the PSD applicability thresholds defined in Rule 62-212.400, F.A.C. Therefore, the plant is an existing PSD-major facility and new projects are subject to review for PSD applicability.

In accordance with the DEP/TECO Consent Final Judgment and the EPA/TECO Consent Decree (Settlement Agreements), TECO was required to re-power the coal fired boilers at the F.J. Gannon Plant with natural gas fired units meeting a NOx standard of 3.5 ppmvd. Shut down of the coal fired boilers created emissions decreases that could be used in a PSD netting analysis. However, TECO could not take advantage of the full emissions decreases because the re-powering project was the result of alleged violations of the new source preconstruction review regulations. Therefore, emissions decreases from the shutdown Gannon Units must be adjusted downward to represent BACT-level controls on the coal-fired units.

Bayside Units 1 and 2, Permit No. PSD-FL-301 (Project No. 0570040-013-AC)

The project proposed the following: construction of Bayside Unit 1 consisting of a 3-on-1 combined cycle gas turbine system to re-power Gannon Unit 5; and construction of Bayside Unit 2 consisting of a 4-on-1 combined cycle gas turbine system to re-power Gannon Unit 6. Based on the PSD netting analysis, this project required determinations of the Best Available Control Technology (BACT) for emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). The project netted out of PSD review for nitrogen oxides (NOx) and sulfur dioxide (SO_2) emissions. However, in accordance with the Settlement Agreements, each gas turbine is required to fire natural gas as the primary fuel and achieve a NOx standard of no more than 3.5 ppmvd. Therefore, Bayside Units 1 and 2 were permitted to fire natural gas as the primary fuel and required to install a selective catalytic reduction (SCR) systems to reduce NOx emissions. Distillate oil was allowed only as a restricted emergency backup fuel in accordance with the EPA/TECO Consent Decree. The permit required the installation of continuous emissions monitoring systems (CEMS) to determine compliance with the CO and NOx emissions standards. See the Technical Evaluation and Preliminary Determination for a full discussion of the PSD netting analysis and BACT determinations.

Bayside Units 3 and 4, Permit No. PSD-FL-301A (Project No. 0570040-015-AC)

In addition to the previously permitted Bayside Units 1 and 2, the project proposed the following: construction of Bayside Unit 3 consisting of a 2-on-1 combined cycle gas turbine system to re-power Gannon Unit 3; and construction of Bayside Unit 4 consisting of a 2-on-1 combined cycle gas turbine system to re-power Gannon Unit 6. Natural gas was requested and specified as the exclusive fuel. Based on the netting analysis, this project netted out of PSD review for NOx and SO_2 emissions. BACT determinations for CO, PM/PM_{10}, and VOC emissions were made for Bayside Units 3 and 4 and revalidated for Bayside Units 1 and 2.

Bayside Units 1 – 4, Permit No. PSD-FL-301B (Project No. 0570040-021-AC)

The project was a permit revision related to monitoring data exclusions in Condition 17. No BACT determinations were required.

Bayside Units 3 and 4, Permit No. PSD-FL-301C (Project No. 0570040-019-AC)

Bayside Units 1 and 2 have been constructed and are in operation. Bayside Units 3 and 4 have not yet been constructed. The project proposed the following: initial construction of Bayside Unit 3A and 3B as simple cycle gas turbines; distillate oil firing for Units 3A and 3B during simple cycle operation (restricted to 700 full load equivalent hours); after an initial phase of simple cycle operation, future conversion of Bayside Units 3A and 3B to combined cycle operation; future construction of Bayside Unit 4 as a combined cycle unit. Based on the netting analysis, this project also netted out of PSD review for NOx and SO_2 emissions. Bayside Units 1 and 2 are in operation and the previous BACT determinations for these units remain unchanged by this permitting action. Bayside Units 3 and 4 have not been constructed and new (re-validated) BACT determinations were made for CO, PM/PM_{10}, and VOC emissions.

SUMMARY OF BACT DETERMINATIONS AND EMISSIONS STANDARDS

Emissions Standards Summaries

The following tables summarize the Department's current BACT determinations and emissions standards.

Table B-1. BACT Emissions Standards for Bayside Units 1 – 4 [a]

Pollutant	Controls [c] and Standards [g]
Fuel Specifications [b]	*Gas Standard*: Pipeline natural gas (≤ 2 grains per 100 SCF, 12 month rolling average) *Oil Standard*: Distillate oil (≤ 0.05% sulfur by weight)
All Modes of Operation - - Compliance Tests [d]	
CO	*Control*: Efficient combustion of clean fuels *Gas Standard*: 7.8 ppmvd @ 15% O_2 (28.7 lb/hour) *Oil Standard*: 9.0 ppmvd @ 15% O_2 (40.5 lb/hour)
PM/PM_{10}	*Controls*: Efficient combustion of clean fuels *Standard*: 10% opacity, 6-minute block average (gas/oil) *Comments*: The CO CEMS serves as a continuous indicator of efficient combustion.
VOC	*Controls*: Efficient combustion of clean fuels *Comments*: The CO CEMS serves as a continuous indicator of efficient combustion.
All Modes of Operation - CEMS Data [e]	
CO (BACT)	*Control*: Efficient combustion of clean fuels *Standard*: 9.0 ppmvd @ 15% O_2, 24-hour block average (gas/oil)

Table B-2. Other Emissions Standards for Bayside Units 1 – 4 [a]

Pollutant	Controls [c] and Standards [g]
Combined Cycle Operation - Compliance Tests [d, h]	
Ammonia	*Standard*: 5 ppmvd @ 15% O_2, combined cycle operation with SCR [f]
NOx	*Controls*: SCR with DLN combustion (gas) *Standard*: 3.5 ppmvd @ 15% O_2 (23.1 lb/hour)
Combined Cycle Operation - CEMS Data [e]	
NOx	*Controls*: SCR plus DLN combustion technology (gas) and wet injection (oil) *Gas Standard*: 3.5 ppmvd @ 15% O_2, 24-hour block average *Oil Standard*: 12.0 ppmvd @ 15% O_2, 24-hour block average
Simple Cycle Operation - Compliance Tests [d]	
NOx	*Controls*: DLN combustion technology (gas) and wet injection (oil) *Gas Standard*: 10.5 ppmvd @ 15% O_2 (69.1 lb/hour) *Oil Standard*: 42.0 ppmvd @ 15% O_2 (320.3 lb/hour)
Simple Cycle Operation - CEMS Data [e]	
NOx	*Controls*: DLN combustion technology (gas) and wet injection (oil) *Gas Standard*: 10.5 ppmvd @ 15% O_2, 24-hour block average *Oil Standard*: 42.0 ppmvd @ 15% O_2, 24-hour block average

Notes:

a. Each gas turbine is a General Electric Model PG7241(FA).

b. Potential SAM and SO_2 emissions are limited by the fuel specifications.

c. "SCR" means selective catalytic reduction system. "DLN" means dry low-NOx combustion technology.

d. Mass emissions rates are based on operation at permitted capacity and a compressor inlet temperature of 59° F.

e. "CEMS" means continuous emissions monitoring system.

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

g. Only Units 3A and 3B are authorized to fire distillate oil. During simple cycle operation of Units 3A and 3B, distillate oil may be fired as a restricted alternate fuel limited to 9,722,300 gallons during any consecutive 12-month period (equivalent to 700 full load equivalent hours of operation). During combined cycle operation of Units 3A and 3B, distillate oil may only be fired as an emergency backup fuel subject to the requirements of the EPA-TECO Consent Decree.

h. Only Units 3A and 3B may fire distillate oil. These units will be installed initially as simple cycle units and later converted to combined cycle operation. Once converted, Units 3A and 3B may only fire distillate oil as an emergency backup fuel. Therefore, no initial NOx compliance test is required for oil firing.

SUMMARY OF MASS EMISSIONS RATES FOR FIRING GAS

Table E-1. Summary of Mass Emission Rates for Firing Natural Gas

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

Notes:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (X);

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

(c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

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

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

(c) Records of monitoring information shall include:

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

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

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

NSPS SUBPART GG REQUIREMENTS

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

Pursuant to 40 CFR 60.332, Standard for Nitrogen Oxides:

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

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

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

Where:

STD = allowable 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)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

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

Department requirement: For natural gas, the "F" value shall be assumed to be 0.

{Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" value provided by the applicant is approximately 10.0 for natural gas. The equivalent emission standard is 108 ppmvd @ 15% oxygen. The permit standards are more stringent than this requirement.}

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

Pursuant to 40 CFR 60.333, Standard for Sulfur Dioxide:

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

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

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

Pursuant to 40 CFR 60.334, Monitoring of Operations:

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

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

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

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

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

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

Department requirement: NOx CEMS data shall substitute for the above requirement because NOx monitoring is required to demonstrate compliance with the permit standards. NOx CEMS data shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

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

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

Pursuant to 40 CFR 60.335, Test Methods and Procedures:

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

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

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

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

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

Where:

NOx	=	emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent
NOxo	=	observed NOx concentration, ppm by volume
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg

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

Ho = observed humidity of ambient air, g H_2O/g air

e = transcendental constant, 2.718

Ta = ambient temperature, °K

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

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

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

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

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

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

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

{Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed in the permit pursuant to Department authority and is consistent with guidance from EPA Region 4.}

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

<u>Department requirement</u>: **The permit species sulfur monitoring methods.**

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

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

SEMIANNUAL CONTINUOUS MONITOR SYSTEMS REPORT

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

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

Reporting period dates: From ____________________ to ____________________

Company: ____________________

Emission Limitation: ____________________

Address: ____________________

Monitor Manufacturer and Model No.: ____________________

Date of Latest CMS Certification or Audit: ____________________

Process Units Description: ____________________

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

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

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

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

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

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

____
Name

____
Title

____
Signature

____
Date

TAMPA ELECTRIC COMPANY
H.L. CULBREATH BAYSIDE POWER STATION
PROJECT NO. 0570040-019-AC
BAYSIDE UNIT 3 – SIMPLE CYCLE OPERATION

Professional Engineer Certification

Professional Engineer Statement:

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

(1) To the best of my knowledge, the information presented in the Tampa Electric Company (TEC) response to the Department's Request for Additional Information (RAI) dated July 13, 2003 concerning Project No. 0570040-019-AC (Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil) are true, accurate, and complete based on my review of material provided by TEC engineering and environmental staff; and

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

Signature: Thomas A. Davis (signed) — Date: 5/5/04

(seal)

* Certification is applicable to the Tampa Electric Company (TEC) response to the Department's Request for Additional Information (RAI) dated July 13, 2003 concerning Project No. 0570040-019-AC (Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil).

TAMPA ELECTRIC COMPANY
H.L. CULBREATH BAYSIDE POWER STATION
PROJECT NO. 0570040-019-AC
BAYSIDE UNIT 3 – SIMPLE CYCLE OPERATION

Professional Engineer Certification

Professional Engineer Statement:

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

(1) To the best of my knowledge, the information presented in the Tampa Electric Company (TEC) response to the Department's Request for Additional Information (RAI) dated May 25, 2004 concerning Project No. 0570040-019-AC (Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil) are true, accurate, and complete based on my review of material provided by TEC engineering and environmental staff; and

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

Thomas W. Davis
Signature

8/25/04
Date

(seal)

* Certification is applicable to the Tampa Electric Company (TEC) response to the Department's Request for Additional Information (RAI) dated May 25, 2004 concerning Project No. 0570040-019-AC (Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil).

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:
Mr. Wade A. Maye, General Manager
H.L. Culbreath Bayside Power Station
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☒ Agent ☐ Addressee

B. Received by (*Printed Name*) Benjamin W.Ilougbby

C. Date of Delivery 1/4/05

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 (*Transfer from service label*) 7000 1670 0013 3109 9014

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

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

7000 1670 0013 3109 9014

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

Postmark Here

Sent To Mr. Wade A. Maye, General Manager
Street, Apt. No.; or PO Box No. Tampa Electric Company
P.O. Box 111
City, State, ZIP+4 Tampa, Florida 33601-0111

PS Form 3800, May 2000 See Reverse for Instructions

TAMPA ELECTRIC

RECEIVED

NOV 13 2003

BUREAU OF AIR REGULATION

November 12, 2003

Mr. Jeffery F. Koerner, P.E.
New Source Review Section
Florida Department of
Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7910 6057 2127

Re: Tampa Electric Company
Bayside Power Station, Unit 3
Project No. 0570040-019-AC
Request for Additional Information

Dear Mr. Koerner:

In response to the request for additional information (received on August 18, 2003) regarding Tampa Electric Company's (TEC) Bayside Unit 3 – Simple Cycle Plus Distillate Oil application, TEC requests additional time to respond pursuant to Rule 62-4.055(1), F.A.C.

> *"Within thirty days after receipt of an application for a permit and the correct processing fee the Department shall review the application and shall request submittal of additional information the Department is authorized by law to request. The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department. If an applicant requires more than ninety days in which to respond to a request for additional information, the applicant may notify the Department in writing of the circumstances, at which time the application shall be held in active status for one additional period of up to ninety days."*

TEC hereby requests an additional 90 days to fully respond to all questions. An e-mail notification of TEC's request has been sent to you, and a FedEx copy will be sent for your files. TEC appreciates the cooperation and consideration of the Department in this matter. If you have any questions, please contact Ms. Greer Briggs or me at (813) 641-5034.

Sincerely,

Greer Briggs for,

Laura R. Crouch
Manager - Air Programs
Environmental, Health & Safety

EA/bmr/GMB128

cc: Mr. Jerry Kissel, FDEP-SW
Mr. Jerry Campbell, EPCHC
Mr. Jim Little, EPA Region 4
Mr. John Bunyak, NPS

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 7, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Wade A. Maye, General Manager
F. J. Gannon Station
Port Sutton Road
Tampa, FL 33619

Re: **Request for Additional Information - Reminder**
Project No. 0570040-019-AC
Permit No. PSD-FL-301B
Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil

Dear Mr. Maye:

On July 22, 2003, the Department received your application and sufficient fee for an air construction permit to add simple cycle operation and restricted distillate oil firing to proposed gas turbine units 3A and 3B at the existing Bayside Power Station in Tampa, Florida. The application was incomplete. On August 13, 2003, the Department requested additional information that would allow continued processing of your application. To date, we have not received the requested additional information. Rule 62-4.055(1) of the Florida Administrative Code requires the following:

> *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department. If an applicant requires more than ninety days in which to respond to a request for additional information, the applicant may notify the Department in writing of the circumstances, at which time the application shall be held in active status for one additional period of up to ninety days. Additional extensions shall be granted for good cause shown by the applicant. A showing that the applicant is making a diligent effort to obtain the requested additional information shall constitute good cause. Failure of an applicant to provide the timely requested information by the applicable deadline shall result in denial of the application."*

It has been more than 80 days since our request for additional information (copy attached). You are reminded that the permit processing time clock has stopped for this project and that we will not continue our review until we receive the additional information. If you require a period of time in addition to the 90 days allowed by rule, please submit a written request indicating the amount of time necessary. If you fail to provide the additional information or request additional time to submit the additional information, the Department will deny your application. If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery F. Koerner
Jeffery F. Koerner
New Source Review Section

cc: Ms. Karen Sheffield, TECO
Ms. Dru Latchman, TECO
Mr. Tom Davis, ECT
Mr. Jerry Kissel, SWD
Mr. Jerry Campbell, HEPC
Mr. Jim Little, EPA Region 4
Mr. John Bunyak, NPS

Jeb Bush
Governor

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

David B. Struhs
Secretary

August ~~July~~ 13, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Wade A. Maye, General Manager
F. J. Gannon Station
Port Sutton Road
Tampa, FL 33619

Re: **Request for Additional Information**
Project No. 0570040-019-AC
Permit No. PSD-FL-301B
Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil

Dear Mr. Maye:

On July 22, 2003, the Department received your application and sufficient fee for an air construction permit for the Bayside Power Station located in Tampa, Florida. The request is to add simple cycle operation and restricted distillate oil firing to proposed gas turbine units 3A and 3B. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. The application requests 8760 hours per year of operation. Will these two gas turbines be used to meet peaking power demands? Provide an estimate of such use based on predicted demands.
2. Provide information that supports the request for carbon monoxide emissions of 30.3 ppmvd when firing oil. The Department has information suggesting that such emissions are typically less than 3 ppmvd and recent permits have established CO standards of 15 ppmvd @ 15% oxygen based on a 24-hour average.
3. Provide information that supports the estimated PM/PM_{10} emissions of 18/34 pounds per hour for gas/oil firing. General Electric typically guarantees particulate matter emission rates of 9/18 pounds per hour when firing gas/oil.
4. Please describe and quantify (if possible) any fugitive emissions associated with this proposed project.
5. The application states that Hillsborough County is currently in attainment/unclassifiable with respect to the State and Federal AAQS. Specifically, what are the current ambient air quality concentrations in the vicinity of the project?
6. The proposed modification will increase emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC) in excess of PSD significant emission rates (Table 62-212.400-2, F.A.C.) The regulations define significant impact levels for CO and PM as well as PSD increments for PM_{10}. Please evaluate the maximum air quality impacts for CO and PM_{10} from the proposed project and compare to the PSD Class II Significant Impact Levels. If required, also provide a PSD increment analysis for PM_{10}.
7. Compare the maximum predicted impacts for all PSD pollutants from the proposed project with the respective *de minimis* ambient impact levels? Is preconstruction ambient air quality monitoring required for the proposed modification?

8. Please identify any PSD Class I areas within 150 km of the project and the approximate distance. If required, please provide an air quality impact analysis for any affected PSD Class I areas including regional haze.

9. Please submit an analysis of impacts on soils, vegetation, and visibility.

10. Pursuant to Rule 62-212.400(3)(h)(5), F.A.C., please provide *information relating to the air quality impacts of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect.*

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery J. Koerner

Jeffery F. Koerner
New Source Review Section

cc: Ms. Karen Sheffield, TECO
Ms. Dru Latchman, TECO
Mr. Tom Davis, ECT
Mr. Jerry Kissel, SWD
Mr. Jerry Campbell, HEPC
Mr. Jim Little, EPA Region 4
Mr. John Bunyak, NPS

TAMPA ELECTRIC

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BUREAU OF AIR REGULATION

February 23, 2004

Mr. Jeffery F. Koerner, P.E.
New Source Review Section
Florida Department of
Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7911 5753 4751

Re: Tampa Electric Company
Bayside Power Station, Unit 3
Project No. 0570040-019-AC
Request for Additional Information

Dear Mr. Koerner:

Tampa Electric Co. (TEC) is requesting an extension to fully respond to the Florida Department of Environmental Protection's (the Department) Request for Additional Information (RAI) received by TEC on August 18, 2003. TEC first requested an extension on November 12, 2003 and was granted an additional ninety days to respond to the Department's RAI.

TEC is fervently working to complete its responses to the Department, and at this time would like to submit a draft of its responses. Additional modeling will be necessary to completely address all of the Department's questions, and TEC requests an extension of time to complete this portion of the responses. TEC hereby requests an additional 90 days to fully respond to all questions. An e-mail notification of TEC's request was sent to you on February 12, 2004, and this correspondence is being sent as a formal copy for your files.

Attached, please find TEC's draft responses to the Department's RAI dated August 13, 2003 and a summary of Hillsborough County's available ambient monitoring data - Attachment A. TEC appreciates the cooperation and consideration of the Department in this matter.

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

Sincerely,

Laura R. Crouch

Laura R. Crouch
Manager - Air Programs
Environmental, Health & Safety

EA/bmr/GMB165

Attachment

cc/attach.: Mr. Jerry Kissel, FDEP-SW
Mr. Jerry Campbell, EPCHC
Mr. Jim Little, EPA Region 4
Mr. John Bunyak, NPS

TECO
TAMPA ELECTRIC

RECEIVED
FEB 24 2004
BUREAU OF AIR REGULATION

February 12, 2004 **DRAFT**

Mr. Jeffery F. Koerner, P.E.
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No.

Re: Request for Additional Information
Project No. 0570040-019-AC
Permit No. PSD-FL-301B
Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your letter dated August 13, 2003 (received by TEC on August 16, 2003), and the Hillsborough County Environmental Protection Commission (EPC) e-mail from Mr. Ronald Day dated August 18, 2003, requesting additional information with regards to Bayside Power Station simple cycle Unit 3. This correspondence is intended to provide a response to each specific issue raised by the Department and the Hillsborough County EPC. For your convenience, TEC has restated each point and provided a response below each specific issue.

FDEP Item 1.
The application requests 8,760 hours per year operation. Will these two gas turbines be used to meet peaking power demands? Provide an estimate of such use based on predicted demands.

TEC Response
Bayside Unit 3 is being constructed to meet general area electric power demands. To provide flexibility in operations, TEC requests authorization to operate each Unit 3 combustion turbine (Units 3A and 3B) in simple cycle mode for up to 8,760 hours per year.

FDEP Item 2.
Provide information that supports the request for carbon monoxide emissions of 30.3 ppmvd when firing oil. The Department has information suggesting that emissions are typically less than 3 ppmvd and recent permits have established CO standards of 15 ppmvd @ 15% oxygen based on a 24-hour average.

TEC Response
The requested CO exhaust concentration of 30.3 ppmvd @ 15% O_2 during oil-firing was based on vendor estimated performance data obtained for the dual fuel, General Electric (GE) 7FA simple cycle combustion turbine (CT) units recently installed at TEC's Polk Power Station (PPS). The Department's PSD permit for the PPS simple cycle CTs established an initial (first 12 months of operation) CO exhaust concentration limit of 33 ppmvd and a CO concentration limit thereafter of 20 ppmvd during oil-firing. Compliance with these CO limits is based on the average of three, one-

hour test runs using EPA Reference Method 10. Consistent with the Department's PSD permit for the PPS simple cycle CTs, TEC requests a CO exhaust concentration limit of 20 ppmvd (based on the average of three, one-hour test runs using EPA RM 10) for Bayside simple cycle Units 3A and 3B during oil-firing.

FDEP Item 3.
Provide information that supports the estimated PM/PM_{10} emissions of 18/34 pounds per hour for gas/oil firing. General Electric typically guarantees particulate matter emission rates of 9/18 pounds per hour when firing gas/oil.

TEC Response
The estimated PM/PM_{10} emissions of 18/34 pounds per hour for gas/oil firing represent PM/PM_{10} emission rates based on stack testing using EPA Reference Methods 201 and 202; i.e., the estimated emissions include both front half filterable and back half condensible PM. The GE PM guarantees of 9/18 pounds per hour when firing gas/oil represent front half filterable PM only; e.g., based on stack testing using EPA Reference Method 5 or 17.

FDEP Item 4.
Please describe and quantify (if possible) any fugitive emissions associated with this proposed project.

TEC Response
Fugitive emissions associated with the project will occur during both the construction phase and during routine operations. Construction related fugitive emissions include PM due to land clearing and grading activities, and mobile construction equipment travel on the project site. Construction will also result in fugitive VOC due to surface coating activities; e.g., equipment painting. These construction related fugitive emissions will be insignificant and temporary in nature.

Fugitive emissions occurring during routine operations include VOC due to fuel equipment leaks; i.e., leaks from pipe flanges, valves, pump seals, storage tanks, etc. Fuels that will be used at Unit 3 include pipeline natural gas (primary fuel) and low sulfur distillate fuel oil (secondary fuel). Fugitive VOC emissions due to leaks from natural gas fuel equipment will be insignificant due to the low number of components in natural gas service and since natural gas is composed primarily of non-VOC methane and ethane. Fugitive VOC emissions from the storage and handling of distillate fuel oil will also be insignificant due to its very low volatility; i.e., distillate fuel oil has a true vapor pressure of only 0.0090 pounds per square inch (psi) at 70°F.

FDEP Item 5.
The application states that Hillsborough County is currently in attainment/unclassifiable with respect to State and Federal AAQS. Specifically, what are the current ambient air quality concentrations in the vicinity of the project?

TEC Response
Available ambient air monitoring data Hillsborough County for 2002 collected by the Department and Hillsborough County EPC are summarized on Attachment A. [Attachment A]

FDEP Item 6.
The proposed modification will increase emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC) in excess of PSD significant emission rates (Table

62-212.400-2, F.A.C.) The regulations define significant impact levels for CO and PM as well as PSD increments for PM_{10}. Please evaluate the maximum air quality impacts for CO and PM_{10} from the proposed project and compare to the PSD Class II Significant Impact Levels. If required, also provide a PSD increment analysis for PM_{10}.

TEC Response
To be provided

FDEP Item 7.
Compare the maximum predicted impacts for all PSD pollutants with the respective *de minimis* ambient impact levels? Is preconstruction ambient air quality monitoring required for the proposed project?

TEC Response
To be provided

FDEP Item 8.
Please identify any PSD Class I areas within 150 km of the project and the approximate distance. If required, please provide an air quality impact analysis for any affected PSD Class I areas including regional haze.

TEC Response
The only PSD Class I area located within 150 km of the project is the Chassahowitzka National Wildlife Refuge (CNWR). The CNWA is located approximately 80 km north, northwest (NNW) of the project site.

PSD Class I increments have been established for SO_2, NO_2, and PM_{10}. Potential emissions from the proposed project will be below the PSD significant emission rates for SO_2 and NO_2 and therefore a Class I area air quality analysis is not required for these two pollutants. Since regional haze is caused primarily by secondary nitrate and sulfate formation due to precursor SO_2 and NO_x emissions, a Class I analysis for regional haze is not considered necessary for the proposed Unit 3 simple cycle project.

Class I area air quality analyses are also not considered to be required for the project due to the large decreases in actual emissions that have occurred due to cessation of operations at the adjacent TEC F.J. Gannon Station. For example, actual 2002 SO_2 and NO_x emissions for F.J. Gannon Station Units 1 through 6 totaled 47,103 and 20,694 tons, respectively, based on Acid Rain Program data. In contrast, potential (i.e., at a 100 percent capacity factor) Unit 3 simple cycle CT annual SO_2 and NO_x emissions are estimated to be 148 and 781 tons, respectively. These potential project annual SO_2 and NO_x emissions are only 0.3 and 3.8 percent, respectively, of the F.J. Gannon Station Units 1 through 6 actual 2002 emission rates. Accordingly, there will be a substantial net <u>decrease</u> in actual air quality impacts at the CNWR due to the cessation of operations at the F.J. Gannon Station, including the future operation of Bayside Unit 3.

FDEP Issue 9.
Please submit an analysis of impacts on soils, vegetation, and visibility.

TEC Response

As noted in the response to FDEP Issue 6. above, project CO and PM_{10} impacts will be below the PSD Class II SILs. The PSD Class II SILs are only a small fraction of the ambient air quality standards (AAQS). For example, the 24-hour PM_{10} PSD Class II SIL is 5 $\mu g/m^3$, or only 3.3 percent of the 150 $\mu g/m^3$ PM_{10} 24-hour AAQS. The AAQS are set at levels that protect the welfare of the public, including impacts on soils and vegetation. Accordingly, the proposed Unit 3 project will have insignificant impacts on soils and vegetation. As noted in the response to FDEP Issue 8. above, there will also be a substantial decrease in actual SO_2 and NO_x emissions due to the cessation of operations at the adjacent F.J. Gannon Station.

No visibility impairment is expected due to the types and quantities of emissions projected for the project. Visible emissions from the Unit 3 simple cycle CTs will be 10 percent opacity or less, excluding water. Emissions of primary particulates and sulfur oxides from the simple cycle units will be low due to the primary use of pipeline quality natural gas. The proposed project will comply with all applicable FDEP requirements pertaining to visible emissions.

FDEP Issue 10.
Pursuant to Rule 62-212.400(3)(h)(5), F.A.C., please provide information relating to the air quality impacts of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect.

TEC Response
The project is located in an industrial area that has not experienced significant general growth since August 7, 1977. The air quality impacts of any major industrial project in the area of the Bayside Power Station would have been subject to a detailed regulatory agency assessment under the PSD permitting program.

Impacts associated with construction of the proposed project will be minor. While not readily quantifiable, the temporary increase in vehicular miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

Bayside Unit 3 is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of the simple cycle units are anticipated. When operational, Unit 3 is projected to generate less than five new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas and distillate fuel oil demand due to operation of the simple cycle units will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

EPC Issue 1(a).
On Page 1-2, TECO talks about their initial plans to construct and operate Bayside Units 3A and 3B in dual-fuel, simple-cycle (SC) mode operation and their future plans to convert these units to combined-cycle (CC) mode by adding HRSG's as currently authorized by Air Permit No. PSD-FL-301A. TECO then states that the timing of this conversion will depend on market conditions.

a) What are the market conditions that will determine when the conversion takes place and what is TECO's best estimate as to when this might occur? What are the market conditions that will determine when the conversion to combined cycle operation takes place and what is TECO's best estimate as to when this might occur?

<u>**TEC Response**</u>
Our plans for conversion of simple cycle Units 3A and 3B to combined cycle mode are uncertain at this time. TEC will provide EPC and the Department with all required permitting information regarding combined cycle operation when our conversion plans become final.

<u>EPC Issue 1(b).</u>
The conversion of Units 3A and 3B to the combined-cycle (CC) mode by adding HRSG's may not be the same as that authorized by Air Permit No. PSD-FL-301A. This is because the combustor used in CC mode is only fueled by natural gas from the pipeline (see Figure 2-4 in the Bayside Power Units 3 and 4 Air Construction Permit Application dated June 2001). It is not clear as to what will happen to the use of distillate fuel oil in Units 3A and 3B after the conversion takes place. Will there be an option to bypass the HRSG and run in the SC mode? On the other hand, would it be possible to operate the HRSG by combusting distillate fuel oil instead of natural gas? If so, should this be considered as a third alternative operating scenario?

<u>**TEC Response**</u>
As note in response to EPC Issue 1(a) above, our plans for conversion of simple cycle Units 3A and 3B to combined cycle mode are uncertain at this time. TEC will provide EPC and the Department with all required permitting information regarding combined cycle operation, including any combined cycle bypass and distillate fuel oil use, when our conversion plans become final.

<u>EPC Issue 1(c).</u>
It is not clear as to what the ambient air quality difference is with respect to the SC mode with either natural gas or distillate fuel oil versus the authorized CC mode. A direct comparison of SC mode, which includes both natural gas and distillate fuel oil, versus CC mode for the various temperatures and loading percentages with respect to emission rates and ambient air concentrations would be helpful.

<u>**TEC Response**</u>
To be provided

EPC Issue 2.
On Pages 26 and 47 of Appendix A (Application for Air Permit Title V Source), both the EM and O2 parameters state that specific CEMS information will be provided to FDEP when available. How soon is when available? In other words, when can we expect this information to be forthcoming?

TEC Response
Specific CEMS information for Units 3A and 3B is expected to become available in the last half of 2004.

EPC Issue 3.
Our Appendix C (Dispersion Modeling Files) did not contain a CD. How do the dispersion modeling files for the PSD Permit Revision compare with those submitted with the Air Construction Permit Application dated June 2001? Do the newer dispersion modeling files only contain data on Units 3A and 3B for the SC mode or do these files contain data for all eleven Bayside units in their respective operating modes?

TEC Response
To be provided

TEC understands that with the submission of this additional information, the Department will continue processing our request for an air construction permit for Bayside Power Station simple cycle Units 3A and 3B. If you have any further questions regarding this matter, please contact me at (813) 641-5034.

Sincerely,

Greer Briggs
Environmental Engineer
Environmental, Health & Safety
Tampa Electric Company

EP\gm\

Attachments

Attachment A

Attachment A. Summary of 2002 Hillsborough County Air Quality Data (Page 1 of 2)

Pollutant	Site Location		Site Address	Site No.	Site UTM Coordinates		Distance From Bayside Unit 3	Direction From Bayside Unit 3	Averaging	Sampling	No. of	Ambient Concentration (ug/m^3)			
	County	City			Easting	Northing	(km)	(Vector °)	Period	Period	Observations	1st High	2nd High	Arithmetic Mean	Standard
PM_{10}	Hillsborough	Tampa	3910 Morrison	12-057-0030	351,455	3,085,360	9	255	24-Hr	Jan-Dec	58	35	32		150[1]
									Annual					20	50[2]
	Hillsborough	Ruskin	US 41 CWU	12-057-0066	362,014	3,086,140	2	129	24-Hr	Jan-Dec	61	59	55		150[1]
									Annual					25	50[2]
	Hillsborough	Tampa	Gardinier	12-057-0083	363,890	3,082,701	6	143	24-Hr	Jan-Dec	45	50.0	36.0		150[1]
									Annual					22.0	50[2]
	Hillsborough	Tampa	Eisenhower Jr HS	12-057-0085	365,199	3,074,807	14	159	24-Hr	Jan-Dec	58	44.0	33.0		150[1]
									Annual					19.0	50[2]
	Hillsborough	Tampa	5012 Causeway Blvd.	12-057-0095	362,100	3,089,240	3	50	24-Hr	Jan-Dec	46	48.0	38.0		150[1]
									Annual					24.0	50[2]
	Hillsborough	Tampa	1105 E. Kennedy	12-057-1002	357,193	3,092,154	5	327	24-Hr	Jan-Dec	60	44.0	40.0		150[1]
									Annual					24.0	50[2]
	Hillsborough	Tampa	4013 Ragg Rd	12-057-1068	352,250	3,109,300	23	340	24-Hr	Jan-Dec	61	29.0	29.0		150[1]
									Annual					17.0	50[2]
	Hillsborough	Tampa	Harbor Island Athletic Club	12-057-1069	357,150	3,090,750	4	316	24-Hr	Jan-Dec	61	46.0	38.0		150[1]
									Annual					22.0	50[2]
	Hillsborough	Brandon	2929 Kingsway	12-057-2002	374,240	3,094,200	16	65	24-Hr	Jan-Dec	60	37.0	35.0		150[1]
									Annual					20.0	50[2]
SO_2	Hillsborough	Tampa	Interbay Bld Ballst	12-057-0053	354,169	3,085,361	6	249	1-Hr	Jan-Dec	8,663	201.7	191.3		
									3-Hr			152.0	120.5		1,300[3]
									24-Hr			47.2	39.3		260[3]
									Annual					10.0	60[2]
	Hillsborough	Tampa	Simmons Park	12-057-0081	355,544	3,069,100	19	194	1-Hr	Jan-Dec	8,708	450.6	330.1		
									3-Hr			272.5	162.4		1,300[3]
									24-Hr			83.8	49.8		260[3]
									Annual					9.2	60[2]
	Hillsborough	Tampa	5012 Causeway Blvd.	12-057-0095	362,100	3,089,240	3	50	1-Hr	Jan-Dec	8,477	442.8	372.0		
									3-Hr			283.0	248.9		1,300[3]
									24-Hr			49.8	47.2		260[3]
									Annual					9.4	60[2]
	Hillsborough	Tampa	9851 Hwy 41 South	12-057-0109	363,758	3,081,853	7	148	1-Hr	Jan-Dec	8,623	429.7	421.8		
									3-Hr			335.4	311.8		1,300[3]
									24-Hr			159.8	123.1		260[3]
									Annual					11.0	60[2]
	Hillsborough	Tampa	Davis Island	12-057-1035	356,851	3,089,908	4	304	1-Hr	Jan-Dec	8,634	503.0	455.9		
									3-Hr			288.2	214.8		1,300[3]
									24-Hr			68.1	62.9		260[3]
									Annual					17.3	60[2]

Attachment A. Summary of 2002 Hillsborough County Air Quality Data (Page 2 of 2)

Pollutant	Site Location: County	Site Location: City	Site Address	Site No.	Site UTM Coordinates: Easting	Site UTM Coordinates: Northing	Distance From Bayside Unit 3 (km)	Direction From Bayside Unit 3 (Vector °)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	Arithmetic Mean	Standard
SO_2	Hillsborough	Plant City	One Raider Place	12-057-4004	389,300	3,096,710	31	73	1-Hr	Jan-Dec	8,696	154.6	141.5		
									3-Hr			112.7	86.5		1,300[3]
									24-Hr			36.7	21.0		260[3]
									Annual					7.6	60[2]
NO_2	Hillsborough	Tampa	Simmons Park	12-057-0081	355,544	3,069,100	19	194	Annual	Jan-Dec	8,692			13.2	100[2]
	Hillsborough	Tampa	5121 Gandy Blvd	12-057-1065	348,560	3,086,060	12	262	Annual	Jan-Dec	8,000			19.9	100[2]
CO	Hillsborough	Tampa	4702 Central Ave	12-057-1070	357,000	3,096,500	9	340	1-Hr	Jan-Dec	8,723	6,095.0	6,095.0		40,000[3]
									8-Hr			5,175.0	4,370.0		10,000[3]
	Hillsborough	Plant City	One Raider Place	12-057-4004	389,300	3,096,710	31	73	1-Hr	Jan-Dec	8,273	3,105.0	2,760.0		40,000[3]
									8-Hr			1,840.0	1,610.0		10,000[3]
O_3	Hillsborough	Tampa	Simmons Park	12-057-0081	355,544	3,069,100	19	194	1-Hr	Jan-Dec	240	186.5	184.5		235[4]
									8-Hr	Jan-Dec	96	151.2	147.2		157[5]
	Hillsborough		14063 County Road 39	45-001-0110	385,500	3,073,260	29	120	1-Hr	Jan-Dec	239	186.5	180.6		235[4]
									8-Hr	Jan-Dec	97	147.2	147.2		157[5]
	Hillsborough	Tampa	Davis Island	12-057-1035	356,851	3,089,908	4	304	1-Hr	Jan-Dec	240	178.6	170.8		235[4]
									8-Hr	Jan-Dec	97	137.4	131.5		157[5]
	Hillsborough	Tampa	5121 Gandy Blvd	12-057-1065	348,560	3,086,060	12	262	1-Hr	Jan-Dec	242	202.2	182.6		235[4]
									8-Hr	Jan-Dec	99	155.1	145.3		157[5]
	Hillsborough	Plant City	One Raider Place	12-057-4004	389,300	3,096,710	31	73	1-Hr	Jan-Dec	244	214.0	178.6		235[4]
									8-Hr	Jan-Dec	99	162.9	149.2		157[5]
Lead	Hillsborough	Tampa	1700 North 66th St	12-057-1066	364,000	3,093,400	7	34	24-Hr		54				
										Jan-Mar				1.00	1.5[2]
										Apr-Jun				0.33	
										Jul-Sep				0.39	
										Oct-Dec				1.27	
	Hillsborough	Tampa	6811 E 14th Street	12-057-1073	364,310	3,093,400	7	36	24-Hr		59				
										Jan-Mar				0.22	1.5[2]
										Apr-Jun				0.23	
										Jul-Sep				0.13	
										Oct-Dec				0.41	

[1] 99th percentile
[2] Arithmetic mean
[3] 2nd high
[4] 4th highest day with hourly value exceeding standard over a 3-year period
[5] Annual 4th highest daily maximum 8-hour average exceeding standard over a 3-year period

*Indicates that the mean does not satisfy summary criteria

Source: FDEP, 2003

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

April 9, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Wade A. Maye, General Manager
Bayside Power Station / F. J. Gannon Station
P.O. Box 111
Tampa, FL 336601-0111

Re: Air Permit Project Status Updates
Bayside Power Station

Dear Mr. Maye:

This is simply a courtesy letter to provide an update on the status of two pending applications for air permits for the Bayside Power Station located on Port Sutton Road in Tampa, Florida.

Project No. 0570040-019-AC
Modification of Air Permit No. PSD-FL-301
Request for a Phase of Simple Cycle Operation for Bayside Unit 3 and the Use of Distillate Oil

Status: We received this application on July 23, 2003 and requested additional information in a letter dated August 13, 2003. On November 7, 2003 we sent a reminder. On November 11, 2003, we received an email request for an additional 90 days, which we approved on November 12, 2003. On February 12, 2004, we received a portion of the additional information marked "draft" and a second request for an additional 90 days by email, which we approved on February 13, 2004. It is our understanding that your consultant continues to work on the questions regarding modeling issues. This application remains incomplete and cannot be processed without the requested additional information. The final deadline for submitting this information is May 11, 2004.

Project No. 0570040-021-AC
Modification of Air Permit No. PSD-FL-301
Request for Minor Modification of Permit Condition 17 (Excess Emissions)

Status: We received this application on February 26, 2004 and requested additional information in a letter dated March 19, 2004. Based on several phone conversations with your staff, we believe that the additional information will be submitted shortly. This application remains incomplete and cannot be processed without the requested additional information. The final deadline for submitting this information is June 20, 2004.

We will resume processing your applications after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, Air Permitting South
Bureau of Air Regulation

cc: Ms. Greer Briggs, TECO
Mr. Tom Davis, ECT
Mr. Jerry Kissel, SWD
Mr. Jerry Campbell, HEPC
Mr. Jim Little, EPA Region 4
Mr. John Bunyak, NPS

TAMPA ELECTRIC

May 10, 2004

RECEIVED

MAY 11 2004

BUREAU OF AIR REGULATION

Mr. Jeffery F. Koerner, P.E.
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7924 9548 3465

Re: Request for Additional Information
Project No. 0570040-019-AC
Permit No. PSD-FL-301A
Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your letter dated August 13, 2003 (received by TEC on August 16, 2003), and the Hillsborough County Environmental Protection Commission (EPC) e-mail from Mr. Ronald Day dated August 18, 2003, requesting additional information with regards to Bayside Power Station simple cycle Unit 3. This correspondence is intended to provide a response to each specific issue raised by the Department and the Hillsborough County EPC. The Responsible Official Certification and the Professional Engineer Certification are provided in Attachment A. For your convenience, TEC has restated each point and provided a response below each specific issue.

<u>FDEP Item 1.</u>
The application requests 8,760 hours per year operation. Will these two gas turbines be used to meet peaking power demands? Provide an estimate of such use based on predicted demands.

<u>TEC Response</u>
Bayside Unit 3 is being constructed to meet general area electric power demands. To provide flexibility in operations, TEC requests authorization to operate each Unit 3 combustion turbine (Units 3A and 3B) in simple cycle mode for up to 8,760 hours per year.

<u>FDEP Item 2.</u>
Provide information that supports the request for carbon monoxide emissions of 30.3 ppmvd when firing oil. The Department has information suggesting that emissions are typically less than 3 ppmvd and recent permits have established CO standards of 15 ppmvd @ 15% oxygen based on a 24-hour average.

<u>TEC Response</u>
The requested CO exhaust concentration of 30.3 ppmvd @ 15% O_2 during oil-firing was based on vendor estimated performance data obtained for the dual fuel, General Electric (GE) 7FA simple cycle combustion turbine (CT) units recently installed at TEC's Polk Power Station (PPS). The Department's PSD permit for the PPS simple cycle CTs established an initial (first 12 months of operation) CO exhaust concentration limit of 33 ppmvd and a CO concentration limit thereafter of 20 ppmvd during oil-firing. Compliance with these CO limits is based on the average of three, one- hour test runs using EPA Reference Method 10. Consistent with the Department's PSD permit for the PPS simple cycle CTs, TEC requests a CO exhaust concentration limit of 20 ppmvd (based on the average of three, one-hour test runs using EPA RM 10) for Bayside simple cycle Units 3A and 3B during oil-firing.

FDEP Item 3.
Provide information that supports the estimated PM/PM_{10} emissions of 18/34 pounds per hour for gas/oil firing. General Electric typically guarantees particulate matter emission rates of 9/18 pounds per hour when firing gas/oil.

TEC Response
The estimated PM/PM_{10} emissions of 18/34 pounds per hour for gas/oil firing represent PM/PM_{10} emission rates based on stack testing using EPA Reference Methods 201 and 202; i.e., the estimated emissions include both front half filterable and back half condensible PM. The GE PM guarantees of 9/18 pounds per hour when firing gas/oil represent front half filterable PM only; e.g., based on stack testing using EPA Reference Method 5 or 17.

FDEP Item 4.
Please describe and quantify (if possible) any fugitive emissions associated with this proposed project.

TEC Response
Fugitive emissions associated with the project will occur during both the construction phase and during routine operations. Construction related fugitive emissions include PM due to land clearing and grading activities, and mobile construction equipment travel on the project site. Construction will also result in fugitive VOC due to surface coating activities; e.g., equipment painting. These construction related fugitive emissions will be insignificant and temporary in nature.

Fugitive emissions occurring during routine operations include VOC due to fuel equipment leaks; i.e., leaks from pipe flanges, valves, pump seals, storage tanks, etc. Fuels that will be used at Unit 3 include pipeline natural gas (primary fuel) and low sulfur distillate fuel oil (secondary fuel). Fugitive VOC emissions due to leaks from natural gas fuel equipment will be insignificant due to the low number of components in natural gas service and since natural gas is composed primarily of non-VOC methane and ethane. Fugitive VOC emissions from the storage and handling of distillate fuel oil will also be insignificant due to its very low volatility; i.e., distillate fuel oil has a true vapor pressure of only 0.0090 pounds per square inch (psi) at 70°F.

FDEP Item 5.
The application states that Hillsborough County is currently in attainment/unclassifiable with respect to State and Federal AAQS. Specifically, what are the current ambient air quality concentrations in the vicinity of the project?

TEC Response
Available ambient air monitoring data Hillsborough County for 2002 collected by the Department and Hillsborough County EPC are summarized on Attachment B.

FDEP Item 6.
The proposed modification will increase emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC) in excess of PSD significant emission rates (Table 62-212.400-2, F.A.C.) The regulations define significant impact levels for CO and PM as well as PSD increments for PM_{10}. Please evaluate the maximum air quality impacts for CO and PM_{10} from the proposed project and compare to the PSD Class II Significant Impact Levels. If required, also provide a PSD increment analysis for PM_{10}.

TEC Response
Initial modeling indicated that CO impacts will be well below the PSD Class II SILs, but that the PSD Class II 24-hour average SIL for filterable PM_{10} would be exceeded during oil-firing. In order to keep project PM_{10} impacts below the PSD Class II SIL, the stack height for the simple cycle CTs will be increased to 150 feet above grade and oil-firing operations will be restricted to no more than a maximum of 11 hours per day. This daily operation restriction is in addition to the previously requested annual operating constraint of no more than 700 hours per year of oil-firing. Simple cycle mode Unit 3 CO and PM_{10} model results with respect to the PSD Class II Significant Impact Levels (SILs) are provided on Attachment C. Accordingly, PSD increment analyses for CO and PM_{10} are not required.

FDEP Item 7.
Compare the maximum predicted impacts for all PSD pollutants with the respective *de minimis* ambient impact levels? Is preconstruction ambient air quality monitoring required for the proposed project?

TEC Response
As shown on Attachment C, project air quality impacts for CO and PM_{10} were found to be below the PSD *de minimis* ambient impact levels for all PSD pollutants. The project net emission rate change for VOC (i.e., 62.1 ton per year [tpy]) is below the PSD *de minimis* ambient level of 100 tpy. Accordingly, preconstruction ambient air quality monitoring is not required for the Unit 3 project. Recent ambient air quality data for monitoring sites located throughout Hillsborough County is provided in Attachment B (see response to FDEP Item 5. above).

FDEP Item 8.
Please identify any PSD Class I areas within 150 km of the project and the approximate distance. If required, please provide an air quality impact analysis for any affected PSD Class I areas including regional haze.

TEC Response
The only PSD Class I area located within 150 km of the project is the Chassahowitzka National Wildlife Refuge (CNWR). The CNWA is located approximately 80 km north, northwest (NNW) of the project site.

PSD Class I increments have been established for SO_2, NO_2, and PM_{10}. Net emission rate changes for the Unit 3 project will be below the PSD significant emission rates for SO_2 and NO_2 and therefore a Class I area air quality analysis is not required for these two pollutants. Since regional haze is caused primarily by secondary nitrate and sulfate formation due to precursor SO_2 and NO_x emissions, a Class I analysis for regional haze is not considered necessary for the proposed Unit 3 simple cycle project.

Class I area air quality analyses are also not considered to be required for the project due to the large decreases in actual emissions that have occurred due to cessation of operations at the adjacent TEC F.J. Gannon Station. For example, actual 2002 SO_2 and NO_x emissions for F.J. Gannon Station Units 1 through 6 totaled 47,103 and 20,694 tons, respectively, based on Acid Rain Program data. In contrast, potential (i.e., at a 100 percent capacity factor) Unit 3 simple cycle CT annual SO_2 and NO_x emissions are estimated to be 148 and 781 tons, respectively. These potential project annual SO_2 and NO_x emissions are only 0.3 and 3.8 percent, respectively, of the F.J. Gannon Station Units 1 through 6 actual 2002 emission rates. Accordingly, there will be a substantial net decrease in actual air quality impacts at the CNWR due to the cessation of operations at the F.J. Gannon Station, including the future operation of Bayside Units 3.

FDEP Issue 9.
Please submit an analysis of impacts on soils, vegetation, and visibility.

TEC Response
As noted in the response to FDEP Issue 6. above, project CO and PM_{10} impacts will be below the PSD Class II SILs. The PSD Class II SILs are only a small fraction of the ambient air quality standards (AAQS). For example, the 24-hour PM_{10} PSD Class II SIL is 5 $\mu g/m^3$, or only 3.3 percent of the 150 $\mu g/m^3$ PM_{10} 24-hour AAQS. The AAQS are set at levels that protect the welfare of the public, including impacts on soils and vegetation. Accordingly, the proposed Unit 3 project will have insignificant impacts on soils and vegetation. As noted in the response to FDEP Issue 8. above, there will also be a substantial decrease in actual SO_2 and NO_x emissions due to the cessation of operations at the adjacent F.J. Gannon Station.

No visibility impairment is expected due to the types and quantities of emissions projected for the project. Visible emissions from the Unit 3 simple cycle CTs will be 10 percent opacity or less, excluding water. Emissions of primary particulates and sulfur oxides from the simple cycle units will be low due to the primary use of pipeline quality natural gas. The proposed project will comply with all applicable FDEP requirements pertaining to visible emissions.

FDEP Issue 10.
Pursuant to Rule 62-212.400(3)(h)(5), F.A.C., please provide information relating to the air quality impacts of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect.

TEC Response
The project is located in an industrial area that has not experienced significant general growth since August 7, 1977. The air quality impacts of any major industrial project in the area of the Bayside Power Station would have been subject to a detailed regulatory agency assessment under the PSD permitting program.

Impacts associated with construction of the proposed project will be minor. While not readily quantifiable, the temporary increase in vehicular miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

Bayside Unit 3 is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of the simple cycle units are anticipated. When operational, Unit 3 is projected to generate less than five new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas and distillate fuel oil demand due to operation of the simple cycle units will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

EPC Issue 1(a).
On Page 1-2, TECO talks about their initial plans to construct and operate Bayside Units 3A and 3B in dual-fuel, simple-cycle (SC) mode operation and their future plans to convert these units to combined-cycle (CC) mode by adding HRSG's as currently authorized by Air Permit No. PSD-FL-301A. TECO then states that the timing of this conversion will depend on market conditions.

What are the market conditions that will determine when the conversion takes place and what is TECO's best estimate as to when this might occur? What are the market conditions that will determine when the conversion to combined cycle operation takes place and what is TECO's best estimate as to when this might occur?

TEC Response
Our plans for conversion of simple cycle Units 3A and 3B to combined cycle mode are uncertain at this time. TEC will provide EPC and the Department with all required permitting information regarding combined cycle operation when our conversion plans become final.

EPC Issue 1(b).
The conversion of Units 3A and 3B to the combined-cycle (CC) mode by adding HRSG's may not be the same as that authorized by Air Permit No. PSD-FL-301A. This is because the combustor used in CC mode is only fueled by natural gas from the pipeline (see Figure 2-4 in the Bayside Power Units 3 and 4 Air Construction Permit Application dated June 2001). It is not clear as to what will happen to the use of distillate fuel oil in Units 3A and 3B after the conversion takes place. Will there be an option to bypass the HRSG and run in the SC mode? On the other hand, would it be possible to operate the HRSG by combusting distillate fuel oil instead of natural gas? If so, should this be considered as a third alternative operating scenario?

TEC Response
As noted in response to EPC Issue 1(a) above, our plans for conversion of simple cycle Units 3A and 3B to combined cycle mode are uncertain at this time. TEC will provide EPC and the Department with all required permitting information regarding combined cycle operation, including any combined cycle bypass and distillate fuel oil use, when our conversion plans become final.

EPC Issue 1(c).
It is not clear as to what the ambient air quality difference is with respect to the SC mode with either natural gas or distillate fuel oil versus the authorized CC mode. A direct comparison of SC mode, which includes both natural gas

and distillate fuel oil, versus CC mode for the various temperatures and loading percentages with respect to emission rates and ambient air concentrations would be helpful.

TEC Response
Additional dispersion modeling for Bayside Unit 3 has been conducted as requested. The additional analysis evaluated the difference in maximum air quality impacts between the previously authorized combined cycle (natural gas-firing) and the proposed simple cycle (for both natural gas-firing and limited oil-firing)) modes of operation for Units 3A and 3B for the year of meteorology previously found to result in the highest project impacts (i.e., 1996). The results of this modeling analysis are provided on Attachment D.

EPC Issue 2.
On Pages 26 and 47 of Appendix A (Application for Air Permit Title V Source), both the EM and O2 parameters state that specific CEMS information will be provided to FDEP when available. How soon is when available? In other words, when can we expect this information to be forthcoming?

TEC Response
Specific CEMS information for Units 3A and 3B is expected to become available in the last half of 2004.

EPC Issue 3.
Our Appendix C (Dispersion Modeling Files) did not contain a CD. How do the dispersion modeling files for the PSD Permit Revision compare with those submitted with the Air Construction Permit Application dated June 2001? Do the newer dispersion modeling files only contain data on Units 3A and 3B for the SC mode or do these files contain data for all eleven Bayside units in their respective operating modes?

TEC Response
A compact disc (CD) is included with this response that contains the initial Appendix C (Dispersion Modeling Files) as well as the additional modeling discussed above in FDEP Items 6 and 7 and EPC Issue 3. The modeling files included on this CD address all eleven Bayside units in their respective operating modes.

TEC understands that with the submission of this additional information, the Department will continue processing our request for an air construction permit for Bayside Power Station simple cycle Units 3A and 3B. If you have any further questions regarding this matter, please contact me at (813) 228-4302.

Sincerely,

Greer Briggs
Environmental Engineer
Environmental, Health & Safety
Tampa Electric Company

EP\gm\GMB179

c/att: Mr. Jerry Kissel, FDEP-SW
Mr. Jerry Campbell, EPCHC
Mr. Jim Little, EPA Region 4
Mr. John Bunyak, NPS

Attachment A – Responsible Official Certification & Professional Engineer Certification
Attachment B – 2002 Hillsborough County Air Quality Data
Attachment C – ISCST Model Results
Attachment D – ISCST Model Results

<u>Attachment A</u>
Responsible Official Certification
Professional Engineer Certification

Responsible Official Certification

I hereby certify that the Prevention of Significant Deterioration (PSD) Application being submitted for Bayside Power Station Unit 3A and 3B is authentic and accurate to the best of my knowledge.

Date: 5/9/04

Signature: Wade A. Maye

Wade A. Maye
General Manager
H.L. Culbreath Bayside Power Station

Attachment B
Summary of 2002 Hillsborough County Air Quality Data

Attachment B. Summary of 2002 Hillsborough County Air Quality Data (Page 1 of 2)

Pollutant	Site Location: County	Site Location: City	Site Address	Site No.	Site UTM Coordinates: Easting	Site UTM Coordinates: Northing	Distance From Bayside Unit 3 (km)	Direction From Bayside Unit 3 (Vector °)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	Arithmetic Mean	Standard
PM_{10}	Hillsborough	Tampa	3910 Morrison	12-057-0030	351,455	3,085,360	9	255	24-Hr	Jan-Dec	58	35	32		150[1]
									Annual					20	50[2]
	Hillsborough	Ruskin	US 41 CWU	12-057-0066	362,014	3,086,140	2	129	24-Hr	Jan-Dec	61	59	55		150[1]
									Annual					25	50[2]
	Hillsborough	Tampa	Gardinier	12-057-0083	363,890	3,082,701	6	143	24-Hr	Jan-Dec	45	50.0	36.0		150[1]
									Annual					22.0	50[2]
	Hillsborough	Tampa	Eisenhower Jr HS	12-057-0085	365,199	3,074,807	14	159	24-Hr	Jan-Dec	58	44.0	33.0		150[1]
									Annual					19.0	50[2]
	Hillsborough	Tampa	5012 Causeway Blvd.	12-057-0095	362,100	3,089,240	3	50	24-Hr	Jan-Dec	46	48.0	38.0		150[1]
									Annual					24.0	50[2]
	Hillsborough	Tampa	1105 E. Kennedy	12-057-1002	357,193	3,092,154	5	327	24-Hr	Jan-Dec	60	44.0	40.0		150[1]
									Annual					24.0	50[2]
	Hillsborough	Tampa	4013 Ragg Rd	12-057-1068	352,250	3,109,300	23	340	24-Hr	Jan-Dec	61	29.0	29.0		150[1]
									Annual					17.0	50[2]
	Hillsborough	Tampa	Harbor Island Athletic Club	12-057-1069	357,150	3,090,750	4	316	24-Hr	Jan-Dec	61	46.0	38.0		150[1]
									Annual					22.0	50[2]
	Hillsborough	Brandon	2929 Kingsway	12-057-2002	374,240	3,094,200	16	65	24-Hr	Jan-Dec	60	37.0	35.0		150[1]
									Annual					20.0	50[2]
SO_2	Hillsborough	Tampa	Interbay Bld Ballst	12-057-0053	354,169	3,085,361	6	249	1-Hr	Jan-Dec	8,663	201.7	191.3		
									3-Hr			152.0	120.5		1,300[3]
									24-Hr			47.2	39.3		260[3]
									Annual					10.0	60[2]
	Hillsborough	Tampa	Simmons Park	12-057-0081	355,544	3,069,100	19	194	1-Hr	Jan-Dec	8,708	450.6	330.1		
									3-Hr			272.5	162.4		1,300[3]
									24-Hr			83.8	49.8		260[3]
									Annual					9.2	60[2]
	Hillsborough	Tampa	5012 Causeway Blvd.	12-057-0095	362,100	3,089,240	3	50	1-Hr	Jan-Dec	8,477	442.8	372.0		
									3-Hr			283.0	248.9		1,300[3]
									24-Hr			49.8	47.2		260[3]
									Annual					9.4	60[2]
	Hillsborough	Tampa	9851 Hwy 41 South	12-057-0109	363,758	3,081,853	7	148	1-Hr	Jan-Dec	8,623	429.7	421.8		
									3-Hr			335.4	311.8		1,300[3]
									24-Hr			159.8	123.1		260[3]
									Annual					11.0	60[2]
	Hillsborough	Tampa	Davis Island	12-057-1035	356,851	3,089,908	4	304	1-Hr	Jan-Dec	8,634	503.0	455.9		
									3-Hr			288.2	214.8		1,300[3]
									24-Hr			68.1	62.9		260[3]
									Annual					17.3	60[2]

Attachment B. Summary of 2002 Hillsborough County Air Quality Data (Page 2 of 2)

Pollutant	Site Location: County	Site Location: City	Site Address	Site No.	Site UTM Coordinates: Easting	Site UTM Coordinates: Northing	Distance From Bayside Unit 3 (km)	Direction From Bayside Unit 3 (Vector °)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	Arithmetic Mean	Standard
SO_2	Hillsborough	Plant City	One Raider Place	12-057-4004	389,300	3,096,710	31	73	1-Hr	Jan-Dec	8,696	154.6	141.5		
									3-Hr			112.7	86.5		1,300[3]
									24-Hr			36.7	21.0		260[3]
									Annual					7.6	60[2]
NO_2	Hillsborough	Tampa	Simmons Park	12-057-0081	355,544	3,069,100	19	194	Annual	Jan-Dec	8,692			13.2	100[2]
	Hillsborough	Tampa	5121 Gandy Blvd	12-057-1065	348,560	3,086,060	12	262	Annual	Jan-Dec	8,000			19.9	100[2]
CO	Hillsborough	Tampa	4702 Central Ave	12-057-1070	357,000	3,096,500	9	340	1-Hr	Jan-Dec	8,723	6,095.0	6,095.0		40,000[3]
									8-Hr			5,175.0	4,370.0		10,000[3]
	Hillsborough	Plant City	One Raider Place	12-057-4004	389,300	3,096,710	31	73	1-Hr	Jan-Dec	8,273	3,105.0	2,760.0		40,000[3]
									8-Hr			1,840.0	1,610.0		10,000[3]
O_3	Hillsborough	Tampa	Simmons Park	12-057-0081	355,544	3,069,100	19	194	1-Hr	Jan-Dec	240	186.5	184.5		235[4]
									8-Hr	Jan-Dec	96	151.2	147.2		157[5]
	Hillsborough		14063 County Road 39	45-001-0110	385,500	3,073,260	29	120	1-Hr	Jan-Dec	239	186.5	180.6		235[4]
									8-Hr	Jan-Dec	97	147.2	147.2		157[5]
	Hillsborough	Tampa	Davis Island	12-057-1035	356,851	3,089,908	4	304	1-Hr	Jan-Dec	240	178.6	170.8		235[4]
									8-Hr	Jan-Dec	97	137.4	131.5		157[5]
	Hillsborough	Tampa	5121 Gandy Blvd	12-057-1065	348,560	3,086,060	12	262	1-Hr	Jan-Dec	242	202.2	182.6		235[4]
									8-Hr	Jan-Dec	99	155.1	145.3		157[5]
	Hillsborough	Plant City	One Raider Place	12-057-4004	389,300	3,096,710	31	73	1-Hr	Jan-Dec	244	214.0	178.6		235[4]
									8-Hr	Jan-Dec	99	162.9	149.2		157[5]
Lead	Hillsborough	Tampa	1700 North 66th St	12-057-1066	364,000	3,093,400	7	34	24-Hr		54				
										Jan-Mar				1.00	1.5[2]
										Apr-Jun				0.33	
										Jul-Sep				0.39	
										Oct-Dec				1.27	
	Hillsborough	Tampa	6811 E 14th Street	12-057-1073	364,310	3,093,400	7	36	24-Hr		59				
										Jan-Mar				0.22	1.5[2]
										Apr-Jun				0.23	
										Jul-Sep				0.13	
										Oct-Dec				0.41	

[1] 99th percentile
[2] Arithmetic mean
[3] 2nd high
[4] 4th highest day with hourly value exceeding standard over a 3-year period
[5] Annual 4th highest daily maximum 8-hour average exceeding standard over a 3-year period

*Indicates that the mean does not satisfy summary criteria

Source: FDEP, 2003

Attachment C
ISCST Model Results – Bayside Unit 3
PSD Class II Significant Impact Level Analysis for CO and PM

Attachment C.
ISCST Model Results - Bayside Unit 3
PSD Class II Significant Impact Level (SIL) Analysis for CO and PM_{10}

Pollutant	Averaging Period	Highest Impacts (µg/m³) 1992	1993	1994	1995	1996	Max.	SIL (µg/m³)	% of SIL (%)	Exceed SIL (Y/N)
PM_{10}	Annual	0.104	0.084	0.121	0.095	0.107	0.121	1	12.1	N
	24-Hour	4.90	4.44	4.06	3.38	4.76	4.90	5	98.1	N
CO	1-Hour	379.4	385.1	394.6	474.9	462.7	474.9	2,000	23.7	N
	8-Hour	167.9	155.9	174.8	175.0	167.8	175.0	500	35.0	N

Source: ECT, 2004.

Attachment D
ISCST Model Results – Bayside Unit 3
Comparison Between Combine Cycle and Simple Cycle Modes

Attachment D.
ISCST Model Results - Bayside Unit 3
Comparison Between Combined Cycle and Simple Cycle Modes

A. Combined Cycle (Gas) Vs. Simple Cycle (Gas - 24 hr/day)

Pollutant	Averaging Period	Change in Impacts ($\mu g/m^3$) 1996
SO_2	Annual	0.0002
	24-Hour	0.8
	3-Hour	6.5
NO_2	Annual	0.2
PM_{10}	Annual	0.0003
	24-Hour	1.2
CO	1-Hour	84.8
	8-Hour	18.0

B. Combined Cycle (Gas) Vs. Simple Cycle (Oil - 11 hr/day)

Pollutant	Averaging Period	Change in Impacts ($\mu g/m^3$) 1996
SO_2	Annual	0.2
	24-Hour	8.1
	3-Hour	113.0
NO_2	Annual	< 0
PM_{10}	Annual	< 0
	24-Hour	0.8
CO	1-Hour	373.0
	8-Hour	119.6

Note: The ISCST3 model will not provide negative impacts, change in impacts < 0 represent lower impacts for SC vs. CC mode.

Source: ECT, 2004.

TAMPA ELECTRIC

RECEIVED

AUG 31 2004

BUREAU OF AIR REGULATION

August 30, 2004

Via FedEx
Airbill No. 7919 2164 7387

Mr. Jeffery F. Koerner, P.E.
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Re: Request for Additional Information
Project No. 0570040-019-AC
Permit No. PSD-FL-301A
Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your letter dated May 25, 2004 (received by TEC on June 2, 2004), This correspondence is intended to provide a response to each specific issue raised by the Department. The Responsible Official Certification and the Professional Engineer Certification are provided in Attachment A. For your convenience, TEC has restated each point and provided a response below each specific issue.

FDEP Item 1.

PSD Permit No. 301A authorizes the construction of Bayside Units 1 through 4 (combined cycle gas turbine systems). Bayside Units 1 and 2 were constructed on schedule and are currently in operation. According to the schedule identified in the PSD permit, Bayside Units 3 and 4 would be complete by May of 2004. The permit also specifies the following, "The permittee shall inform the Department and Compliance Authority of any substantial changes to the construction schedule." Please provide an updated schedule of construction for Bayside Units 3 and 4.

TEC Response

TEC's current expansion plan indicates the need for additional capacity in 2006. TEC is reviewing options to either self-build or purchase simple cycle (SC) Bayside Units 3a & 3b. As a result, TEC is providing the FDEP with an updated schedule for the construction of simple cycle (SC) Bayside Units 3a & 3b:

May 2005 – Commencement of construction for SC Bayside Units 3a & 3b.

FDEP Item 2.
TECO completed construction and began commercial operation of Bayside Unit 2D on September 19, 2003, which was the last gas turbine in the initial construction phase to come on line. Since this date, the Department understands that no additional work has been performed to add combined cycle Bayside Units 3 and 4. The authority to construct these units expires on July 1, 2005. As a result of TECO's uncertain plans, will the Bayside Unit 3 simple cycle project replace the previously permitted combined cycle Bayside Units 3-4 project? Please explain.

TEC Response
TEC began commercial operation of Bayside Unit 2 after first fire of the last Bayside combustion turbine (CT). As a result, TEC makes the following correction to FDEP Item 2 above: *TEC completed construction and began commercial operation of Bayside Unit 2C on November 19, 2003, which was the last gas turbine in the initial construction phase to come on line.* Since this date TEC has not done any additional work to add combined cycle Bayside Units 3 and 4. As stated in *FDEP Item 1* above, TEC is currently reviewing options to either self-build or purchase SC CT's and expects to complete this analysis by the Spring of 2005. Based on the most cost effective option, TEC understands that construction would need to commence by the first half of 2005, since the authority to construct these units expires on July 1, 2005, and that if the deadline to commence construction under this permit is not met, that additional permitting will be required. At this time TEC is only considering SC operation for Bayside Unit 3 (3a & 3b). Should TEC decide to convert Bayside Units 3a & 3b to combined cycle, TEC understands that additional permitting would also be required.

FDEP Item 3.
The initial PSD permit recognized the staggered construction schedule to complete Bayside Units 1-2 first and Bayside Units 3-4 would follow. Although it is possible to extend the PSD permit expiration date to complete the Bayside Unit 3 project, construction must begin before March 19, 2005 to maintain the original BACT determination. This date represents 18 months after completing construction of the last Bayside Unit (2D). If construction on Bayside Unit 3 does not begin by this time, TECO must first demonstrate the adequacy of the BACT determination prior to beginning construction. See Condition 9 in Section II of the PSD permit. As a result, a new BACT determination will likely be more stringent. Please comment and provide a schedule for the Bayside Unit 3 project.

TEC Response
Based on the revised date for FDEP Item 2 above, TEC makes the following changes: *Although it is possible to extend the PSD permit expiration date to complete the Bayside Unit 3 project, that construction must begin before May 20, 2005 to maintain the original BACT determination. This date represents 18 months after completing construction of the last Bayside Unit (2C).* As mentioned in FDEP Item 1 above, TEC's current expansion plan requires additional capacity in 2006, with construction of these SC CT's likely to begin by May 2005. TEC understands that construction must begin before May 20, 2005, to

maintain the original BACT determination, and that if construction does not begin by such a date, that a new, more stringent BACT determination may be likely.

FDEP Item 4.
Attachment A represents a schedule of completed and future activities for Gannon Units 1 through 6 and Bayside Units 1 through 4. Based on this schedule, it appears that emissions decreases from the shutdown of Gannon Units 1-6 would be available until 2008. Please comment.

TEC Response
Yes, this is the case.

FDEP Item 5.
As of your last submittal, the coal-fired Gannon units have all been permanently shut down. Please summarize the current status of, and future plans for, the coal storage and handling activities

TEC Response
The discussion of the coal-fired Gannon units is addressed in the Title V permit Renewal application. Please reference the H.L. Culbreath Bayside Title V Renewal application submitted on July 1, 2004.

FDEP Item 6.
In your response, the following project specifications were modified: the simple cycle stack heights were increased to 150 feet; the daily distillate oil firing was restricted to an equivalent 11 hours/day; and the annual distillate oil firing remained limited to an equivalent of 700 hours/year. These will become conditions of the permit. In addition, EPA Region 4 maintains that the EPA Consent Decree prohibits oil firing in any re-powered unit as long as natural gas is available. As summarized below, the Consent Decree allows only very limited firing of distillate oil as a backup fuel.

- The unit cannot fire natural gas;
- The backup fuel must be No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight;
- The unit fires oil for an equivalent of no more than 875 hours per year;
- All air pollution controls are functional and used to the maximum extent possible for the unit; and
- The unit is in compliance with the emissions standards of this permit.

The Department is awaiting final comments from EPA Region 4 regarding oil firing during an initial phase of simple cycle operation for Bayside Unit 3. Please provide any comments you would like considered. Is TECO requesting the capability to fire distillate oil after Bayside Unit 3 is converted to combined cycle operation?

TEC Response

TEC submitted comments to the United States Environmental Protection Agency's (USEPA) Jim Little on July 2, 2004, for consideration regarding Bayside Unit 3 oil firing capabilities. See Attachment B.

FDEP Item 7.

The following summary is an attempt to clarify the PSD "BACT" and PSD "modeling" requirements for this project.

PSD BACT: TECO entered into settlement agreements with EPA and the Department to resolve alleged violations of the New Source Review requirements. With regard to PSD applicability and *BACT determinations*, it was determined that "past actual" emissions must be based on actual emissions *as if BACT-level controls were already installed.* For illustrative purposes, Table 1 in Attachment B shows this analysis based on decreases from the shutdown of Gannon Units 1 through 6 (past actual emissions with BACT-level controls), increases from the startup of Bayside Units 1 and 2 (potential emissions), and increases from the simple cycle startup of Bayside Unit 3 (potential emissions). The analysis shows that the project triggers PSD BACT review for CO, PM, and VOC, which is consistent with TECO's conclusion.

PSD Modeling: For purposes of determining the PSD *modeling requirements*, the actual emissions from Gannon Units 1 through 6 *does not* consider the actual emissions as if BACT-level controls were already installed. Instead, the full decreases from shutdown of these units were allowed. For illustrative purposes, Table 2 in Attachment B summarizes this analysis, which shows that the project triggers the PSD *modeling requirements* for CO and VOC. There are no modeling requirements for VOC. However, TECO did perform a PSD significant impact analysis that shows modeled impacts from the project are not significant for CO or PM. Therefore, no additional modeling was necessary.

Please provide any comments.

TEC Response

PSD BACT: TEC has no further comment.

PSD Modeling: **TEC agrees that no additional modeling is necessary.**

FDEP Item 8.

TECO also has an open application to make minor revisions to the existing PSD permit (Project No. 0570040-021-AC). Does TECO request that these two projects be merged into a single project with final permit modification?

<u>**TEC Response**</u>
No. TEC does not request that these two projects be merged into a single project. TEC would like to keep these two projects separate.

TEC understands that with the submission of this additional information, the Department will continue processing our request for an air construction permit for Bayside Power Station simple cycle Units 3A and 3B. If you have any further questions regarding this matter, please contact me at (813) 228-4302.

Sincerely,

Greer Briggs
Environmental Engineer
Environmental, Health & Safety

EHS\bmr\GMB202

c/att: Mr. Jerry Kissel, FDEP-SW
Mr. Jerry Campbell, EPCHC
Mr. Jim Little, EPA Region 4
Mr. John Bunyak, NPS

<u>Attachment A</u>
Responsible Official Certification
Professional Engineer Certification

I, the undersigned, am the responsible official as defined in Chapter 62-213, F.A.C., of the Title V source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and data contained in this document are true, accurate, and complete.

Wade A. Maye (signature) — 8/30/04

Signature — Date

Wade A. Maye — General Manager, Bayside Power Station

Name — Title

Attachment B

AP7.6

TAMPA ELECTRIC

July 2, 2004

Mr. Jim Little
U.S. Environmental Protection Agency – Region 4
Acid Rain Program (6204J)
401 M St., SW
Washington, D.C. 20460

Via FedEx
Airbill No. 7901 9691 0918

Re: Tampa Electric Company
H.L. Culbreath Bayside Power Station
Unit 3 Simple Cycle plus Distillate Oil Operation
Permit Number: PSD-FL-301A
AIRS 0570040

Dear Mr. Little:

Per Tampa Electric Company's (TEC) telephone conversation with Mr. David Lloyd from the United States Environmental Protection Agency (USEPA) on May 28, 2004, this correspondence is being sent to address the Consent Decree requirements for oil firing for the H.L. Culbreath Bayside Power Station (Bayside) Unit 3 project, which will add simple cycle operation and restricted distillate oil firing to the proposed gas turbine units 3A and 3B.

On June 2, 2004, TEC received a request for additional information (RAI) No. 2 from the Florida Department of Environmental Protection (FDEP). Question 6 provided a summary of oil firing that is allowed under the Consent Decree. FDEP has stated that it is awaiting comments from EPA Region 4 regarding oil firing during an initial phase of simple cycle (SC) operation for Bayside Unit 3, but has requested that TEC provide any comments that it would like the Department to consider. To address the oil firing issue at Bayside, TEC has re-stated the requirements of the Consent Decree as it applies to the re-powering of Gannon Station below:

> *Under Consent Decree Paragraph 26.C,*
>
> *A Unit Re-Powered under this or any other provision of this Consent Decree may be fired with No. 2 fuel oil if and only if: (1) the Unit cannot be fired with natural gas; (2) the Unit has not yet been fired with No. 2 fuel oil as a back-up fuel for more than 875 full load*

> *equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil; (3) the oil to be used in firing the Unit has a sulphur content of less than 0.05 percent (by weight);, (4) Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and (5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.*
>
> *Re-Power is defined by the Consent Decree in Paragraph 18, as follows:*
>
> *<u>Re-Power</u> shall mean the removal or permanent disabling of devices, systems, equipment, and ancillary or supporting systems at a Gannon or Big Bend Unit such that the Unit cannot be fired with coal; and the installation of all devices, systems, equipment, and ancillary or supporting systems needed to fire such Unit with natural gas under the limits set in this Consent Decree (or with No. 2 fuel oil, as a back up fuel only, and under the limits specified by this Consent Decree) plus installation of the control technology and compliance with the Emission Rates called for under this Consent Decree.*

Based upon this information, the requirements of the Consent Decree apply only to the re-powering of a Gannon or Big Bend Station unit. Bayside Unit 3 is a stand alone, SC combustion turbine (CT) that will not require re-powering of a Gannon Station unit. TEC understands that if Bayside Unit 3 is converted to combined cycle operation and a Gannon Station unit is re-powered, then the requirements of limited oil firing under the Consent Decree may become applicable. At this time, TEC is only considering SC operation for Bayside Unit 3. TEC does not believe that any of the requirements of the Consent Decree apply.

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

Sincerely,

Greer Briggs, for

Laura R. Crouch
Manager – Air Programs
Environmental, Health & Safety

EA/bmr/GMB192

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

TAMPA ELECTRIC

November 23, 2004

RECEIVED

NOV 24 2004

BUREAU OF AIR REGULATION

Via FedEx
Airbill No. 7919 8664 4661

Mr. Jeffery F. Koerner, P.E.
New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Avenue, Suite 4
Tallahassee, Florida 32301

Re: **Request for Additional Information**
Project No. 0570040-019-AC
Permit No. PSD-FL-301A
Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your letter dated September 28, 2004 (received by TEC on October 25, 2004), requesting additional information with regards to Bayside Power Station simple cycle Unit 3. This correspondence is intended to provide a response to each specific issue raised by the Department. The Responsible Official Certification is provided in Attachment A. For your convenience, TEC has restated each point and provided a response below each specific issue.

FDEP Item 1.
Your response indicates that you will proceed with firm plans for simple cycle operation for Bayside Units 3 and 4 to begin construction in May of 2005. Future conversion of Units 3 and 4 to combined cycle operation is uncertain and will require additional permitting. Therefore, the Department intends to modify the PSD permit to reflect only simple cycle operation of Units 3 and 4.

TEC Response
After speaking with the Department's Jeff Koerner on November 3, 2004, and receiving e-mailed correspondence on November 8, 2004, TEC understands that the Department will issue the PSD permit for BPS Units 3 and 4 to reflect both simple cycle (SC) and combined cycle (CC) operation. The Department has agreed to re-authorize construction of the CC Units 3 and 4, authorizing distillate oil firing in accordance with the EPA-TECO Consent Decree. The BACT determinations for both SC and CC operation will be valid for 18 months from final permit issuance. If Units 3A and 3B begin construction within this period, the BACT determination is valid for SC operation (phase I), and once Units 3A and 3B are in operation, the BACT determination will remain valid for CC operation (phase II) for an additional 18 months provided the emissions decreases from the retired Gannon Units are still within the 5-year contemporaneous period. These start to fall out beginning in 2008.

TAMPA ELECTRIC COMPANY
P. O. BOX 111 TAMPA, FL 33601-0111
(813) 228-4111
CUSTOMER SERVICE:
HILLSBOROUGH COUNTY (813) 223-0800
OUTSIDE HILLSBOROUGH COUNTY 1 (888) 223-0800

FDEP Item 2.
On July 2, 2004, TECO sent EPA Region 4 a letter describing the use of distillate oil for Bayside Units 3 and 4 simple cycle project. Please provide EPA Region 4's response.

TEC Response
TEC received a copy of the e-mailed response from EPA to the Department on October 13, 2004. A copy of the e-mail is attached for reference.

TEC understands that with the submission of this additional information, the Department will continue processing our request for an air construction permit for Bayside Power Station simple cycle Units 3A and 3B. If you have any further questions regarding this matter, please contact me at (813) 228-4302.

Sincerely,

Greer Briggs
Environmental Engineer
Environmental, Health & Safety

EHS/bmr/GMB209

Attachments

c/att: Mr. Jerry Kissel, FDEP-SW
Mr. Jerry Campbell, EPCHC
Mr. Jim Little, EPA Region 4
Mr. John Bunyak, NPS
Mr. David Lloyd, EPA Region 4

Attachment A
Responsible Official Certification

Responsible Official Certification

I, the undersigned, am the Responsible Official as defined in Chapter 62-213, F.A.C., of the Title V source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and data contained in this document are true, accurate, and complete.

Date: 11/23/04

Signature: Wade A. Maye
Wade A. Maye
General Manager
H.L. Culbreath Bayside Power Station

Attachment B
Response to Item #2 from EPA Region 4

From: "Koerner, Jeff" <Jeff.Koerner@dep.state.fl.us>
To: "Greer Briggs" <gmbriggs@tecoenergy.com>, <tdavis@ectinc.com>
Date: 10/14/2004 3:17:13 PM
Subject: FW: TECO Bayside Station - Addition of Simple Cycle Units w/Distillate Oil Firing

Greer and Tom,

Below is the response I got from David Lloyd at EPA Region 4.

Jeff Koerner, BAR - Air Permitting South
Florida Department of Environmental Protection
850/921-9536

-----Original Message-----
From: Lloyd.David@epamail.epa.gov [mailto:Lloyd.David@epamail.epa.gov]
Sent: Wednesday, October 13, 2004 4:05 PM
To: Koerner, Jeff
Cc: Little.James@epamail.epa.gov; TMariani@enrd.usdoj.gov
Subject: Re: TECO Bayside Station - Addition of Simple Cycle Units w/Distillate Oil Firing

Jeff,

I am in agreement with the assessment that until the new turbines are incorporated into a repowering project, the terms of the Consent Decree addressing fuel oil do not apply. I will add that we interpret the "cannot be fired with natural gas" language for the repowered units in a strict manner and that natural gas costs alone would not be sufficient reason to use oil. A breach in a natural gas pipeline disrupting flow, for example, would be sufficient rationale to satisfy the "cannot be fired with..." language.

The other issue I requested information on in my May 28, 2004 conversation with TECO was concerning how the Consent Decree might impact the level of emissions control applied to the two CTs (BACT or something less) . I was concerned about whether or not any CD-required emissions reductions could be used to offset or net against increases from the turbines. TECO's letter is silent on this issue.

Therefore, my questions are...has there been a determination that the new combustion turbines will have BACT installed? If not, what was the rationale? If netting was used was it based on CD-required reductions? I will seek input from others at EPA and DOJ on these issues depending on the input here.

David

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

May 25, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Wade A. Maye, General Manager
F. J. Gannon Station
Port Sutton Road
Tampa, FL 33619

Re: **Request for Additional Information No. 2**
Project No. 0570040-019-AC
Permit No. PSD-FL-301B
Bayside Unit 3 – Simple Cycle Operation Plus Distillate Oil

Dear Mr. Maye:

On July 22, 2003, the Department received your application for an air construction permit for the Bayside Power Station located in Tampa, Florida. The request is to add simple cycle operation and restricted distillate oil firing to proposed gas turbine units 3A and 3B. On August 13, 2003, the Department requested additional information. On May 11, 2004, the Department received your response to this request. The application remains incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. PSD Permit No. 301A authorizes the construction of Bayside Units 1 through 4 (combined cycle gas turbine systems). Bayside Units 1 and 2 were constructed on schedule and are currently in operation. According to the schedule identified in the PSD permit, Bayside Units 3 and 4 would be complete by May of 2004. The permit also specifies the following, "The permittee shall inform the Department and Compliance Authority of any substantial changes to the construction schedule." Please provide an updated schedule of construction for Bayside Units 3 and 4.
2. TECO completed construction and began commercial operation of Bayside Unit 2D on September 19, 2003, which was the last gas turbine in the initial construction phase to come on line. Since this date, the Department understands that no additional work has been performed to add combined cycle Bayside Units 3 and 4. The authority to construct these units expires on July 1, 2005. As a result of TECO's uncertain plans, will the Bayside Unit 3 simple cycle project replace the previously permitted combined cycle Bayside Units 3-4 project? Please explain.
3. The initial PSD permit recognized the staggered construction schedule to complete Bayside Units 1-2 first and Bayside Units 3-4 would follow. Although it is possible to extend the PSD permit expiration date to complete the Bayside Unit 3 project, construction must begin before March 19, 2005 to maintain the original BACT determination. This date represents 18 months after completing construction of the last Bayside Unit (2D). If construction on Bayside Unit 3 does not begin by this time, TECO must first demonstrate the adequacy of the BACT determination prior to beginning construction. See Condition 9 in Section II of the PSD permit. As a result, a new BACT determination will likely be more stringent. Please comment and provide a schedule for the Bayside Unit 3 project.
4. Attachment A represents a schedule of completed and future activities for Gannon Units 1 through 6 and Bayside Units 1 through 4. Based on this schedule, it appears that emissions decreases from the shutdown of Gannon Units 1-6 would be available until 2008. Please comment.
5. As of your last submittal, the coal-fired Gannon units have all been permanently shut down. Please summarize the current status of, and future plans for, the coal storage and handling activities.
6. In your response, the following project specifications were modified: the simple cycle stack heights were increased to 150 feet; the daily distillate oil firing was restricted to an equivalent 11 hours/day; and the annual distillate oil firing

remained limited to an equivalent of 700 hours/year. These will become conditions of the permit. In addition, EPA Region 4 maintains that the EPA Consent Decree prohibits oil firing in any re-powered unit as long as natural gas is available. As summarized below, the Consent Decree allows only very limited firing of distillate oil as a backup fuel.

- The unit cannot fire natural gas;
- The backup fuel must be No. 2 distillate oil (or a superior grade) containing less than 0.05% sulfur by weight;
- The unit fires oil for an equivalent of no more than 875 hours per year;
- All air pollution controls are functional and used to the maximum extent possible for the unit; and
- The unit is in compliance with the emissions standards of this permit.

The Department is awaiting final comments from EPA Region 4 regarding oil firing during an initial phase of simple cycle operation for Bayside Unit 3. Please provide any comments you would like considered. Is TECO requesting the capability to fire distillate oil after Bayside Unit 3 is converted to combined cycle operation?

7. The following summary is an attempt to clarify the PSD "BACT" and PSD "modeling" requirements for this project.

   PSD BACT: TECO entered into settlement agreements with EPA and the Department to resolve alleged violations of the New Source Review requirements. With regard to PSD applicability and *BACT determinations*, it was determined that "past actual" emissions must be based on actual emissions *as if BACT-level controls were already installed*. For illustrative purposes, Table 1 in Attachment B shows this analysis based on decreases from the shutdown of Gannon Units 1 through 6 (past actual emissions with BACT-level controls), increases from the startup of Bayside Units 1 and 2 (potential emissions), and increases from the simple cycle startup of Bayside Unit 3 (potential emissions). The analysis shows that the project triggers PSD BACT review for CO, PM, and VOC, which is consistent with TECO's conclusion.

   PSD Modeling: For purposes of determining the PSD *modeling requirements*, the actual emissions from Gannon Units 1 through 6 *does not* consider the actual emissions as if BACT-level controls were already installed. Instead, the full decreases from shutdown of these units were allowed. For illustrative purposes, Table 2 in Attachment B summarizes this analysis, which shows that the project triggers the PSD *modeling requirements* for CO and VOC. There are no modeling requirements for VOC. However, TECO did perform a PSD significant impact analysis that shows modeled impacts from the project are not significant for CO or PM. Therefore, no additional modeling was necessary.

   Please provide any comments.

8. TECO also has an open application to make minor revisions to the existing PSD permit (Project No. 0570040-021-AC). Does TECO request that these two projects be merged into a single project with final permit modification?

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery J. Koerner

Jeffery F. Koerner, Air Permitting South
DARM – Bureau of Air Regulation

cc: Ms. Karen Sheffield, TECO
Ms. Greer Briggs, TECO
Mr. Tom Davis, ECT
Mr. Jerry Kissel, SWD
Mr. Jerry Campbell, HEPC
Mr. Jim Little, EPA Region 4
Mr. John Bunyak, NPS

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:

Mr. Wade A. Maye
General Manager
F. J. Gannon Station
Port Sutton Road
Tampa, FL 33619

2. 7001 0320 0001 3692 5405

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*)

B. Date of Delivery 8/19/01

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

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

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

7001 0320 0001 3692 5405

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

Sent To Wade A. Maye
Street, Apt. No.; or PO Box No. Port Sutton Road
City, State, ZIP+4 Tampa, FL 33619

PS Form 3800, January 2001 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:

Mr. Wade A. Maye
General Manager
F. J. Gannon Station
Port Sutton Road - P.O. Box 111
Tampa, FL 33619

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*) JC CHAPUE
B. Date of Delivery 11/13-03

C. Signature
X
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

NOV 13 2003

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*)
7000 2870 0000 7028 3451

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

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

7000 2870 0000 7028 3451

OFFICIAL USE

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

Postmark Here

Sent To
Wade A. Maye
Street, Apt. No.; or PO Box No.
Port Sutton Rd., - PO Box 111
City, State, ZIP+ 4
Tampa, FL 33619

PS Form 3800, May 2000 See Reverse for Instructions

no small Receipt

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:

Wade A. Maye, General Manager
Tampa Electric Company
Bayside / Gannon Station
PO Box 111
Tampa, FL 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X
☐ Agent
☒ Addressee

B. Received by (*Printed Name*)

C. Date of Delivery

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BUREAU OF AIR REGULATION

July 21, 2003

Ms. Trina Vielhauer
Florida Department of
Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Via FedEx
Airbill No. 7922 9151 1549

Re: Bayside Power Station Units 3A and 3B
Air Construction Permit Application
Application Fee Submittal

Dear Ms. Vielhauer:

Please find enclosed a check in the amount of $7,500 submitted in support of the Bayside Power Station Units 3A and 3B Air Construction Permit Application. Also enclosed is the Responsible Official signature page. If you have questions, please contact Dru Latchman or me at (813) 641-5358.

Sincerely,

Laura R. Crouch

Laura R. Crouch
Manager-Air Programs
Environmental Affairs

EA/bmr/DNL183

Enclosure

c: Mr. Jerry Kissel - FDEP SW
Ms. Alice Harman - EPCHC
J. Kahn
J. Nelson
G. Worley, EPA
J. Bunyak, NPS

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

(813) 228-4111

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

TABLE OF CONTENTS

TABLE OF CONTENTS
(Continued, Page 2 of 2)

LIST OF TABLES

LIST OF TABLES
(Continued, Page 2 of 2)

LIST OF FIGURES

1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

The existing Tampa Electric Company (TEC) F.J. Gannon Station (Gannon) consists of six steam boilers (Units 1 through 6), six steam turbines, one simple-cycle combustion turbine (SCCT) (CT-1), a once-through cooling water system, storage and handling of solid fuels, fluxing material, fly ash, slag, fuel oil storage tanks, and ancillary support equipment. Gannon is located on Port Sutton Road in Tampa, Hillsborough County, Florida. Units 1 and 2 each have a nominal generation capacity of 125 megawatts (MW). Units 3, 4, 5, and 6 each have a nominal generation capacity of 180, 188, 239, and 414 MW, respectively. CT-1 has a nominal generation capacity of 14 MW. Units 1 through 6 are all fired with solid fuels; CT-1 is fired with No. 2 distillate fuel oil. Gannon Units 1 through 6 are scheduled to be retired no later than December 31, 2004, per the U.S. Environmental Protection Agency (EPA)/TEC Consent Decree signed in February 2000.

The TEC Bayside Power Station (Bayside) is currently being constructed at the existing Gannon site. Upon completion, Bayside will consist of 11 combined-cycle combustion turbines (CCCTs). Bayside Unit 1 includes three CCCTs (designated as Bayside Units 1A, 1B, and 1C) and will be used to repower existing F.J. Gannon Station Unit 5. Bayside Unit 2 includes four CCCTs (designated as Bayside Units 2A, 2B, 2C, and 2D) and will be used to repower existing F.J. Gannon Station Unit 6. Bayside Units 3 and 4 each include two CCCTs (designated as Bayside Units 3A, 3B, 4A, and 4B) and will be used to repower existing F.J. Gannon Station Units 3 and 4, respectively.

TEC submitted air construction permit applications to the Florida Department of Environmental Protection (FDEP) for Bayside Units 1 and 2 in September 2000 and for Bayside Units 3 and 4 in June 2001. In response, FDEP issued Air Permit No. PSD-FL-301 addressing the construction and initial operation of Units 1 and 2 on March 30, 2001. This permit was subsequently revised to include all 11 Bayside CCCTs (i.e., Units 1 through 4) and reissued as Air Permit No. PSD-FL-301A.

As presently authorized by Air Permit No. PSD-FL-301A, each Bayside CCCT is comprised of a natural gas-fired General Electric (GE) 7FA combustion turbine (CT) equipped with an unfired heat recovery steam generator (HRSG) for operating in combined-cycle (CC) mode. Based on projected future demands for electricity, TEC requests the addition of dual fuel, simple-cycle (SC) mode operation to Bayside Units 3A and 3B as an alternative operating scenario to the presently authorized natural gas CC operating mode.

TEC plans to initially construct and operate Bayside Units 3A and 3B in dual-fuel SC mode operation. Each SCCT will be equipped with an inlet air evaporative cooling system and fired primarily with pipeline-quality natural gas. Low-sulfur (containing no more than 0.05 weight percent sulfur) distillate fuel oil will serve as a secondary fuel source. Bayside SC Units 3A and 3B will operate at an annual capacity factor of up to 100 percent. At baseload operation, this annual capacity factor is equivalent to 8,760-hours-per-year (hr/yr) operation. TEC proposes to limit the use of distillate fuel oil in Bayside SC Units 3A and 3B to no more than an 8-percent capacity factor (i.e., no more than 700 hr/yr at baseload). In the future, TEC plans to convert Bayside SC Units 3A and 3B to CC mode by adding HRSGs as currently authorized by Air Permit No. PSD-FL-301A. The timing of this future conversion will depend on market conditions.

Condition No. 26 of the EPA/TEC Consent Decree requires the repowering of no less than 200 MW of Gannon coal-fired generating capacity Units by May 1, 2003, and a total of 550 MW by December 31, 2004. Bayside CC Units 1 and 2 will satisfy this repowering requirement. Accordingly, the provisions of the EPA/TEC Consent Decree are not applicable to Bayside SC Units 3A and 3B.

This submittal provides a complete air permit application to incorporate the proposed addition of dual fuel, SC mode operation to Bayside Units 3A and 3BConstruction of Bayside SC Units 3A and 3B is scheduled to begin in October 2004 and May 2005, respectively. Construction is expected to take 1 year for each Unit resulting in construction completion of Bayside SC Units 3A and 3B in October 2005 and May 2006, respectively.

Before the commercial operation of Bayside SC Units 3A and 3B, the existing coal fired operation at Gannon will permanently cease operation. With the exception of carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM) and particulate matter less than or equal to 10 microns in aerodynamic diameter (PM_{10}), there will be a substantial net reduction in emissions of other pollutants subject to review under the Prevention of Significant Deterioration (PSD) New Source Review (NSR) permitting program due to the elimination of emissions from Gannon Units 3 through 6. The net increases in CO, VOC, and PM/PM_{10} emissions due to the netting of Gannon Units 3 through 6 with Bayside Units 1 through 4 (including SC Units 3A and 3B) will exceed the PSD significant emission rates for these pollutants. Accordingly, Bayside SC Units 3A and 3B are subject to the PSD NSR requirements of Section 62-212.400, Florida Administrative Code (F.A.C.) for CO, VOC, and PM/PM_{10} emissions.

Since operation of the proposed Bayside SC Units 3A and 3B will result in airborne emissions, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), F.A.C. This report, including the required permit application forms and supporting documentation contained in the appendices, constitutes TEC's application for authorization to commence construction in accordance with (FDEP permitting rules contained in Chapter 62-212, F.A.C.

Bayside SC Units 3A and 3B will be located in an attainment area and will have net CO, VOC, and PM/PM_{10} emissions increases in excess of 100, 40, and 15 tons per year (tpy), respectively. Consequently, Bayside SC Units 3A and 3B qualify as major modifications to an existing major facility and are subject to the PSD NSR requirements of Rule 62-212.400, F.A.C., for CO, VOC, and PM/PM_{10}. Therefore, this report and application is also submitted to satisfy the permitting requirements contained in the FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes national and state air quality standards and discusses applicability of NSR procedures to the proposed project.
- Section 4.0 provides an analysis of best available control technology (BACT) for CO, VOC, and PM/PM_{10}.
- Sections 5.0 (Dispersion Modeling Methodology) and 6.0 (Dispersion Modeling Results) address ambient air quality impacts.

Appendix A contains the FDEP Application for Air Permit—Long Form, and the regulatory applicability tables. The emission rate calculations are shown in Appendix B. All dispersion modeling input and output files for the ambient impact analysis is provided in Appendix C.

1.2 SUMMARY

Bayside SC Unit 3 will consist of two simple-cycle CT units. The CTs will be dual-fired with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per one hundred standard cubic feet (gr S/100 scf), and distillate fuel oil containing no more than 0.05-weight percent sulfur.

The planned construction start dates for Bayside SC Units 3A and 3B are October 2004 and May 2005, respectively. The planned construction completion dates for Bayside SC Units 3A and 3B are October 2005 and May 2006, respectively.

Based on an evaluation of the anticipated worst-case annual operating scenario, Bayside SC Unit 3 will have the potential to emit 781.2 tpy of nitrogen oxides (NO_x), 293.9 tpy of CO, 168.9 tpy of PM/PM_{10}, 142.9 tpy of sulfur dioxide (SO_2), 29.8 tpy of VOCs, and 0.3 tpy of lead. Regarding noncriteria pollutants, Bayside SC Unit 3 will potentially emit 17.0 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of metals and organic compounds.

As presented in this report, the analyses required for this permit application resulted in the following conclusions:

- The net increase in emissions following the cessation of operation of Gannon Units 3 through 6 with Bayside Units 1 through 4 (including SC Units 3A and 3B) will be below the Table 212.400-2, F.A.C., significant emission rates for all regulated air pollutants, with the exception of CO, VOC, PM/PM_{10}. Accordingly, Bayside SC Unit 3 is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for CO, VOC, and PM/PM_{10} only. Based on actual historical emission rates adjusted for the retroactive application of NO_x, SO_2, and PM BACT, the elimination of Gannon Units 3 through 6 and addition of Bayside Units 1 through 4 will result in a net decrease of 2,029.6 tpy of SO_2, 1,021.8 tpy of NO_x, 33.3 tpy of H_2SO_4 mist, 0.5 tpy of lead, and a net increase of 816.0 tpy of CO, 62.1 tpy of VOC, and 92.0 tpy of PM/PM_{10}. Actual emission rate decreases (i.e., without the retroactive BACT adjustments) will be considerably greater.
- Emissions of PM/PM_{10}, SO_2, and H_2SO_4 mist will be controlled by the use of pipeline-quality natural gas and low-ash and low-sulfur distillate fuel oil.
- NO_x emissions will be controlled by the use of dry low-NO_x (DLN) combustors (natural gas firing) and water injection (distillate oil firing). The NO_x SCCT exhaust concentration will be 10.5 parts per million by dry volume (ppmvd) corrected to 15-percent oxygen for natural gas firing, and 42 ppmvd at 15-percent oxygen for distillate fuel oil firing.
- Advanced burner design and good operating practices to minimize incomplete combustion will be employed to control CO emissions. Maximum short-term CO SCCT exhaust concentration will be 7.8 ppmvd at 15-percent oxygen for natural gas firing and 30.3 ppmvd at 15-percent oxygen for distillate fuel oil firing. Cost effectiveness of a CO oxidation catalyst control system was determined to be $5,626 per ton of CO. Due to the high control costs, installation of a CO oxidation catalyst control system is considered to be economically infeasible.

- Advanced burner design and good operating practices to minimize incomplete combustion will be employed to control VOC emissions. The maximum SCCT VOC exhaust concentration is projected to be 1.2 ppmvd at 15-percent oxygen for natural gas firing and 3.0 ppmvd for distillate fuel oil firing at 15-percent oxygen. Cost effectiveness of a VOC oxidation catalyst control system was determined to be $99,878 per ton of VOC. Due to the high control costs, installation of a VOC oxidation catalyst control system is considered to be economically infeasible.
- Bayside Units 1 through 4 will have potential emissions of hazardous air pollutants (HAPs) less than the major source thresholds of 10 tpy for any individual HAP and 25 tpy for total HAPs. Bayside is therefore not subject to the case-by-case maximum achievable control technology (MACT) requirements of Section 112(g)(2)(B) of the 1990 Clean Air Act Amendments (CAAA).

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

Bayside SC Unit 3 will be located at the existing TEC Gannon station. Gannon is situated on Port Sutton Road in Tampa, Hillsborough County, Florida. Figure 2-1 provides portions of a U.S. Geological Survey (USGS) topographical map showing the Gannon site location and nearby prominent geographical features.

Bayside SC Unit 3 will consist of two, simple-cycle GE PG7241 (FA) CTs. Each SCCT will be capable of producing a nominal 165 MW of electricity. The two Bayside Unit 3 SCCTs are designated as Units 3A and 3B. The SCCTs will be fired with pipeline quality natural gas. Low sulfur distillate fuel oil will serve as a back-up fuel source.

Bayside Unit 3 will operate at an annual capacity factor of up to 92 and 8 percent for natural gas and distillate fuel oil firing, respectively. Capacity factor is defined as the ratio of the SCCT's actual annual electric output (in Units of megawatts electrical per hour [MWe-hr]) to the unit's nameplate capacity times 8,760 hours. At baseload operation, these annual capacity factors are equivalent to 8,060 hr/yr for natural gas firing and 700 hr/yr for distillate fuel oil firing. The SCCTs will normally operate between 50- and 100-percent load.

Combustion of natural gas and fuel oil in the SCCTs will result in emissions of PM/PM_{10}, SO_2, NO_x, CO, VOCs, and H_2SO_4 mist. Emission control systems proposed for the simple-cycle CTs include the use of DLN combustors (natural gas firing) and water injection (distillate fuel oil firing) to control NO_x; good combustion practices for control of CO and VOCs; and exclusive use of clean, low-sulfur, low-ash natural gas and distillate fuel oil to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions.

Figure 2-2 provides a plot plan of the Bayside Power Station showing the Bayside SC Unit 3 layout, major process equipment and structures, and the new SCCT emission points. Figure 2-3 provides a profile view. Primary access to the Bayside Power Station

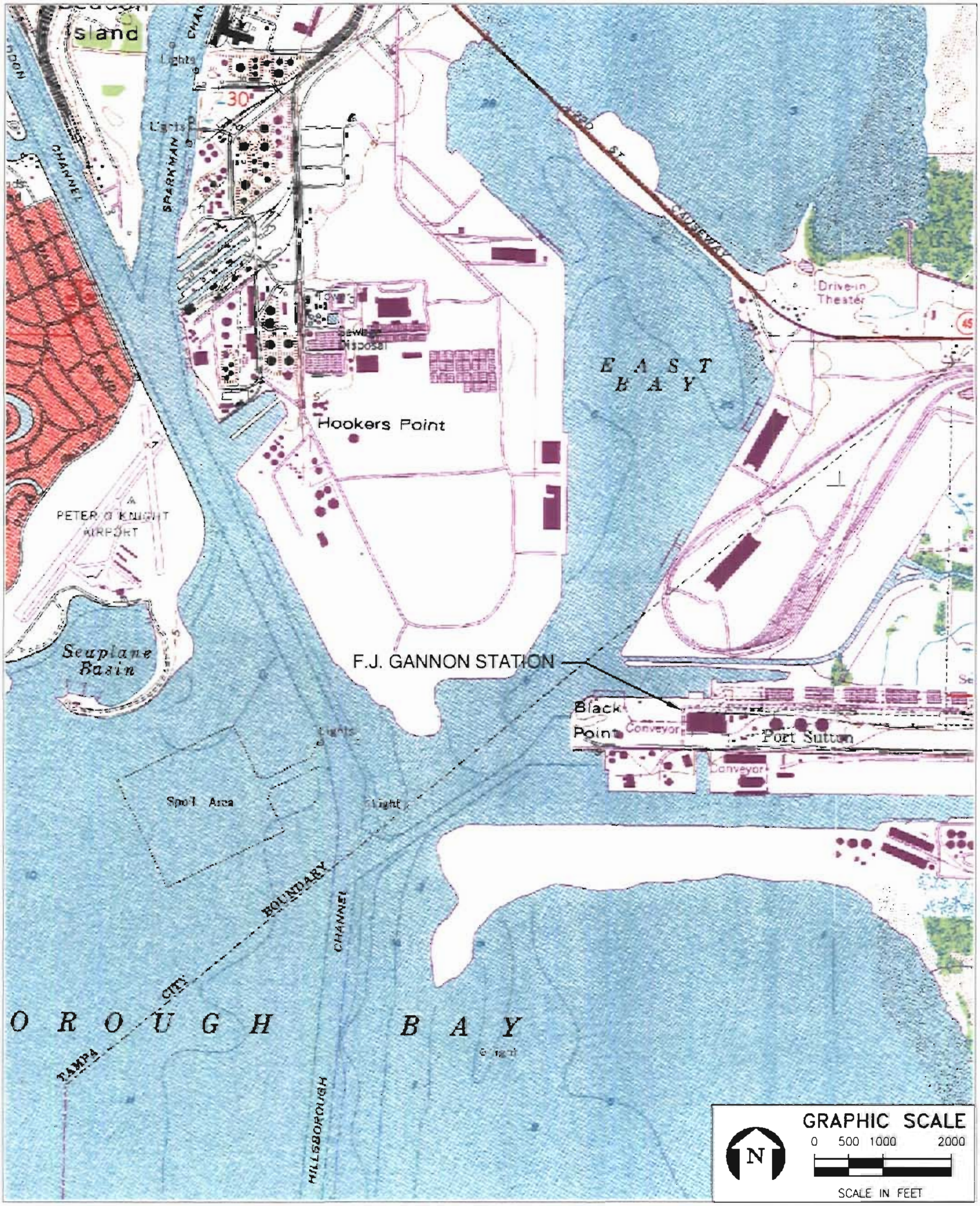

FIGURE 2-1.

F.J. GANNON STATION LOCATION AND SURROUNDINGS

Source: USGS Quad: TAMPA, 1981; ECT, 2003.

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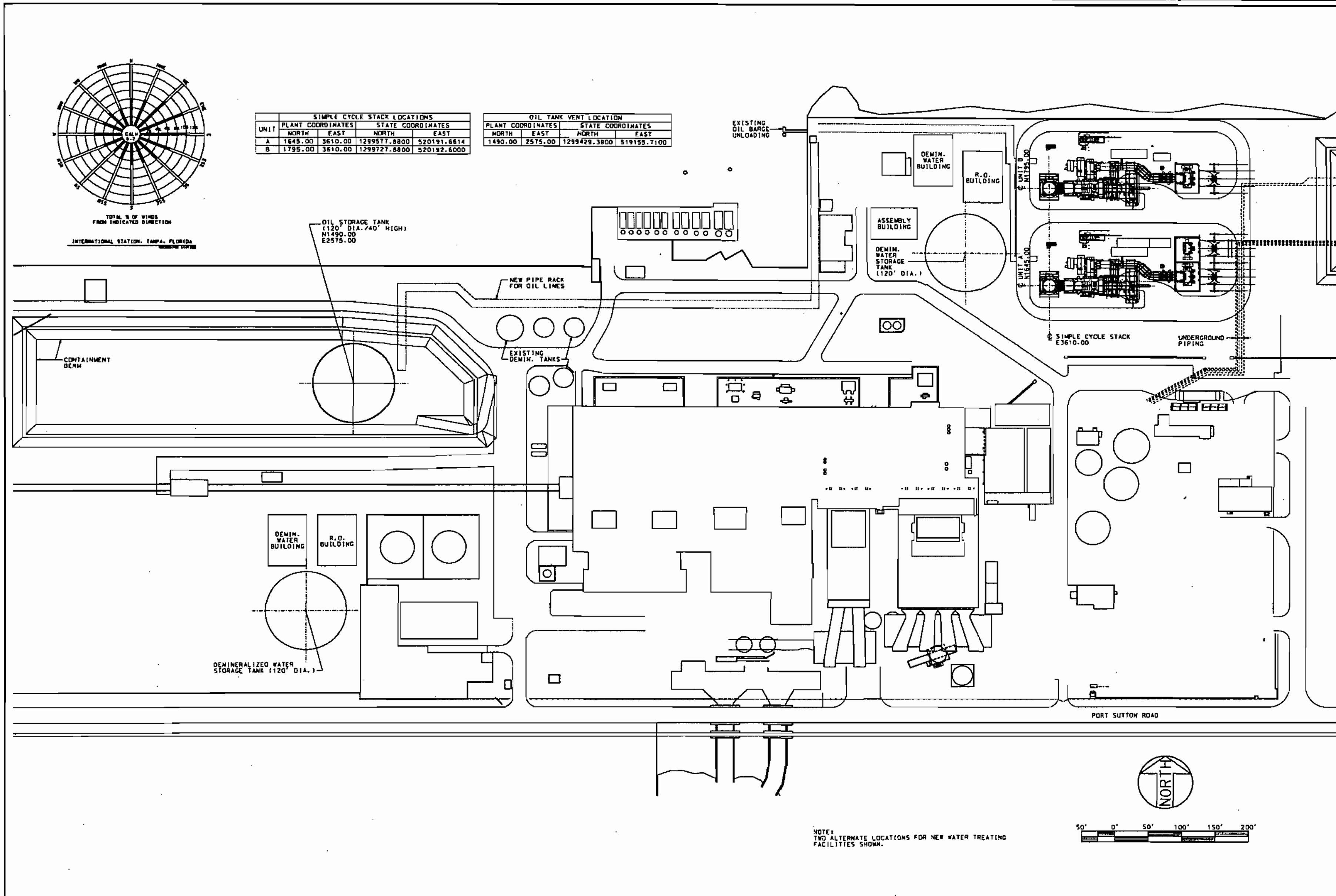

UNIT	SIMPLE CYCLE STACK LOCATIONS			
	PLANT COORDINATES		STATE COORDINATES	
	NORTH	EAST	NORTH	EAST
A	1645.00	3610.00	1299577.8800	520191.6614
B	1795.00	3610.00	1299727.8800	520192.6000

OIL TANK VENT LOCATION			
PLANT COORDINATES		STATE COORDINATES	
NORTH	EAST	NORTH	EAST
1490.00	2575.00	1299429.3800	519155.7100

FIGURE 2-2.

BAYSIDE UNIT 3 PLOT PLAN

Source: TEC, 2003.

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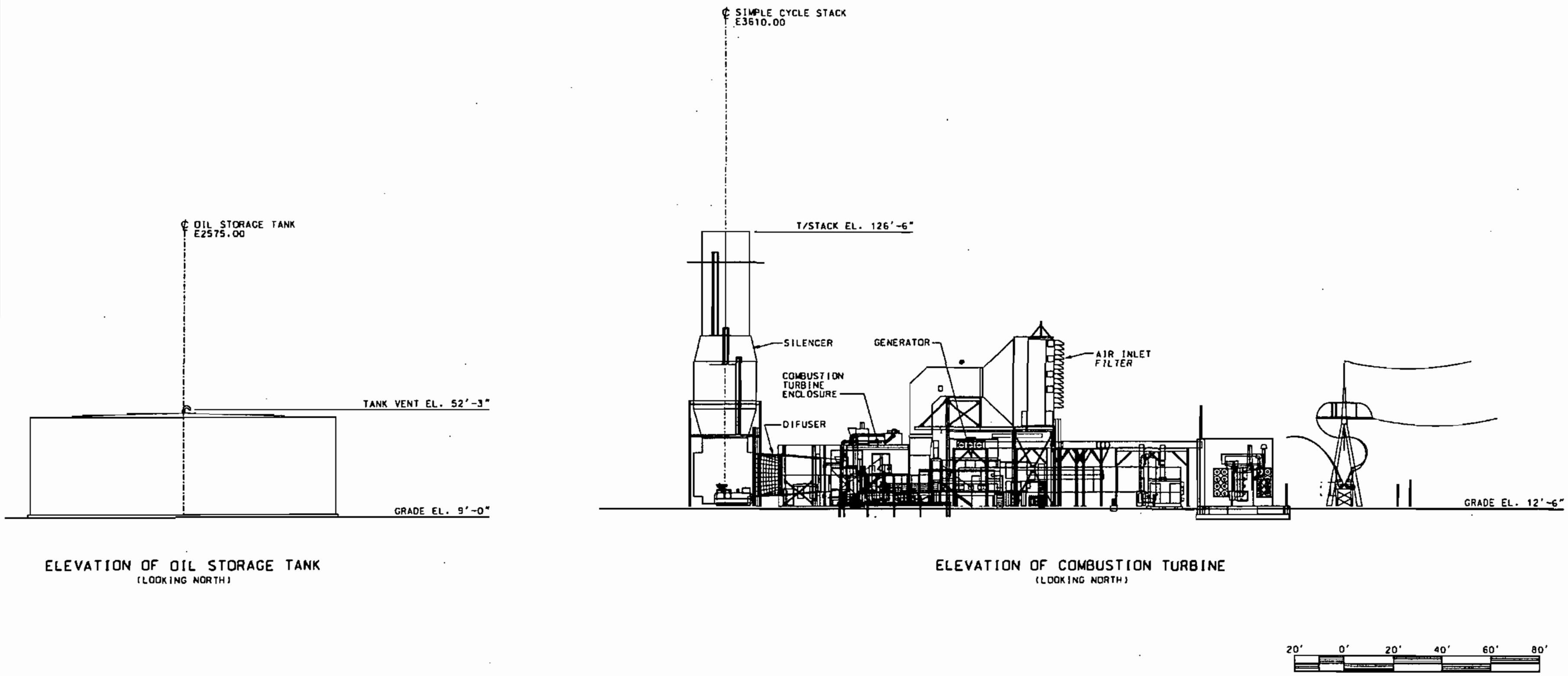

FIGURE 2-3.

BAYSIDE UNIT 3 PROFILE

Source: TEC, 2003.

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will be from Port Sutton Road on the south side of the site. The Bayside Power Station entrance will have security to control site access.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

Bayside Unit 3 will include two nominal 165-MW CTs operating in simple-cycle mode. Figure 2-4 presents a process flow diagram for Bayside Unit 3.

CTs are heat engines that convert latent fuel energy into work using compressed hot gas as the working medium. CTs deliver mechanical output by means of a rotating shaft used to drive an electrical generator, thereby converting a portion of the engine's mechanical output to electrical energy. Ambient air is first filtered and then compressed by the CT compressor. On warm days, the CT inlet air may be conditioned by the use of evaporative coolers. The CT compressor increases the pressure of the combustion air stream and also raises its temperature. The compressed combustion air is then combined with natural gas fuel and burned in the CT's high-pressure combustor to produce hot exhaust gases. These high-pressure, hot gases next expand and turn the CT to produce rotary shaft power, which is used to drive an electric generator as well as the CT combustion air compressor.

Normal operation is expected to consist of the Bayside Unit 3 SCCTs firing natural gas or fuel oil at baseload. Alternate operating modes include reduced load (i.e., between 50 and 100-percent of baseload), and SCCT inlet air evaporative cooling. SCCT CO and VOC exhaust concentrations are expected to remain essentially constant from 50- to 100-percent load. However, it is possible that CO and VOC exhaust concentrations will also remain essentially unchanged at lower loads (e.g., 45-percent load). For this reason, TEC requests the same permit condition authorizing lower load operations for Bayside SC Unit 3 as specified in Section III, Condition 17.b. of Department Air Permit No. PSD-FL-301A, Project No. 0570040-015-AC, recently issued for Bayside Units 1 through 4. As noted previously, the simple-cycle CTs may operate at an annual capacity factor of up to 100 percent.

Vendor information indicates that the Bayside Unit 3 7FA SCCTs will have a heat input of 1,772 and 1,947 million British thermal Units power hour (MMBtu/hr), higher heating

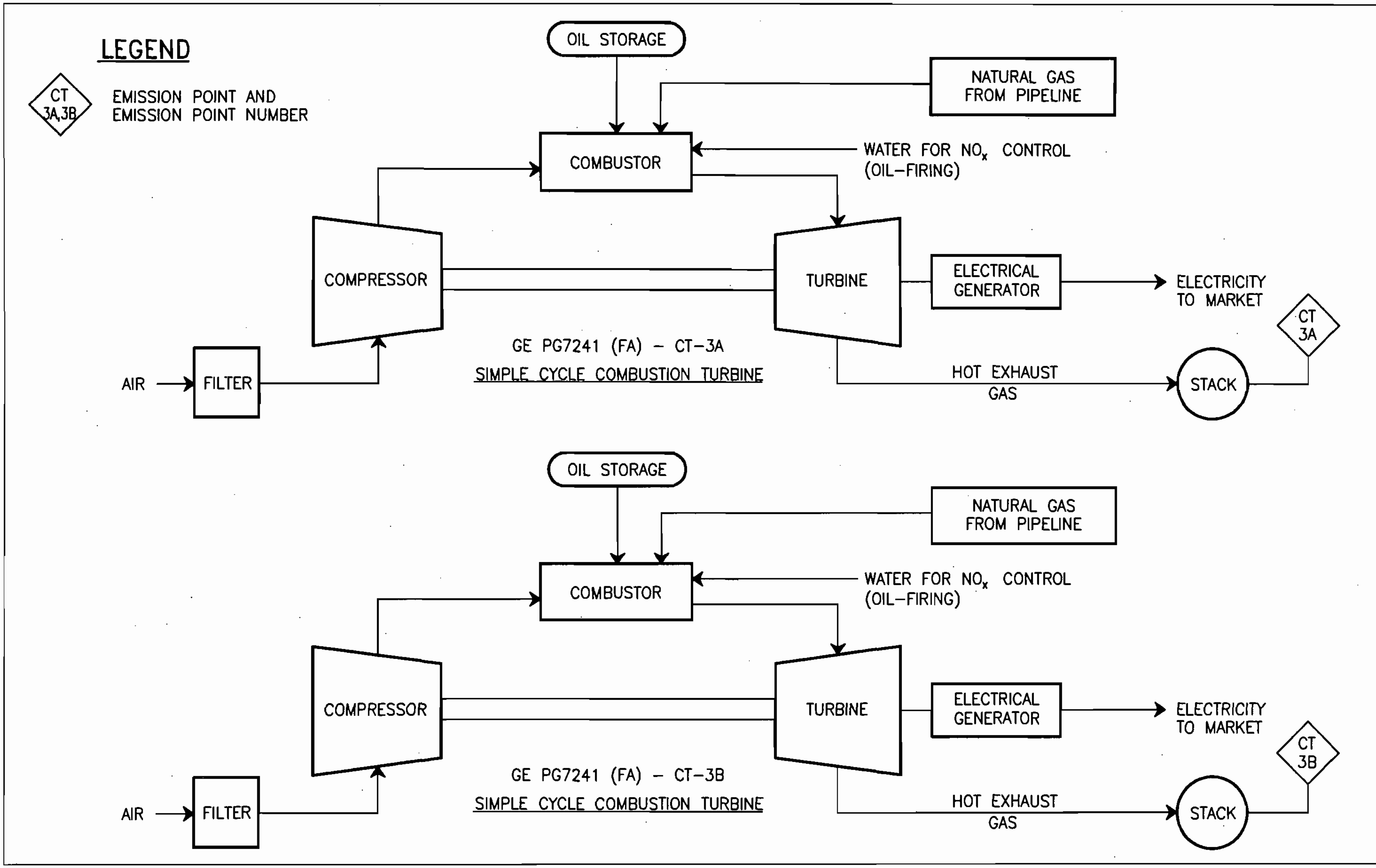

FIGURE 2-4.

BAYSIDE UNIT 3: SCCT PROCESS FLOW DIAGRAM

Source: ECT, 2003.

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value (HHV) at baseload and 59 degrees Fahrenheit (°F) ambient temperature for natural gas and distillate fuel oil firing, respectively. However, CT vendors typically include a margin in guaranteed heat rates, and, therefore, actual heat inputs could be somewhat higher than provided on the vendor expected performance data sheets. In addition, CT heat rates will gradually increase over time due to routine CT operation and degradation. TEC has therefore estimated heat input rates based on a 3.5-percent margin to allow for heat rate degradation over time consistent with the approach taken for Bayside Units 1 and 2.

The SCCTs will use DLN combustion technology (natural gas firing) and water injection (distillate fuel oil firing) to control NO_x air emissions. The exclusive use of low-sulfur natural gas and low-ash/low-sulfur fuel oil in the SCCTs will minimize PM/PM_{10}, SO_2, and H_2SO_4 mist air emissions. High efficiency combustion practices will be employed to control CO and VOC emissions.

2.3 EMISSION AND STACK PARAMETERS

Tables 2-1 and 2-2 provide maximum hourly criteria pollutant emission rates (per SCCT unit) for natural gas and distillate fuel oil firing, respectively. Table 2-3 summarizes maximum hourly H_2SO_4 mist emission rates. Maximum hourly noncriteria pollutant rates are provided in Tables 2-4 and 2-5 for natural gas and distillate fuel oil firing, respectively. The highest hourly emission rates for each pollutant are shown, taking into account load and ambient temperature to develop maximum hourly emission estimates for each SCCT.

Maximum hourly emission rates for all pollutants, in Units of pounds per hour (lb/hr), are projected to occur for SCCT operations at baseload and low ambient temperature (i.e., 20°F). Appendix B provides the basis for these emission rates.

Table 2-6 presents projected maximum annual criteria and noncriteria emissions for Bayside SC Unit 3. The maximum annualized rates were conservatively estimated assuming baseload operation for 8,060 hr/yr (gas firing), 700 hr/yr (oil firing), and an ambient temperature of 59°F. As noted previously, coal fired operation at existing Gannon Units 3

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures (per SCCT)—Natural Gas

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	18.0	2.27	10.2	1.28	73.8	9.30	30.5	3.84	3.0	0.38	Neg.	Neg.
	59	18.0	2.27	9.5	1.20	69.1	8.71	30.5	3.84	3.0	0.38	Neg.	Neg.
	90†	18.0	2.27	8.8	1.10	63.0	7.94	30.0	3.79	3.0	0.38	Neg.	Neg.
75	20	18.0	2.27	8.2	1.03	58.6	7.38	30.0	3.79	2.6	0.33	Neg.	Neg.
	59	18.0	2.27	7.7	0.97	55.1	6.94	30.5	3.84	2.6	0.33	Neg.	Neg.
	90†	18.0	2.27	7.2	0.91	51.5	6.49	30.9	3.89	2.8	0.35	Neg.	Neg.
50	20	18.0	2.27	6.5	0.82	45.7	5.76	31.3	3.95	2.8	0.35	Neg.	Neg.
	59	18.0	2.27	6.2	0.78	43.3	5.46	32.2	4.05	2.8	0.35	Neg.	Neg.
	90†	18.0	2.27	5.8	0.73	41.0	5.17	33.0	4.16	2.8	0.35	Neg.	Neg.

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible

*Excludes H_2SO_4 mist.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: GE, 1998.
ECT, 2003.

Table 2-2. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures (per SCCT)—Distillate Fuel Oil

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	34.0	4.28	107.8	13.58	339.4	42.76	69.7	8.79	7.7	0.97	0.104	0.013
	59	34.0	4.28	101.5	12.79	320.3	40.35	69.1	8.70	7.7	0.97	0.098	0.012
	90†	34.0	4.28	92.3	11.63	291.2	36.69	68.6	8.64	7.5	0.95	0.093	0.012
75	20	34.0	4.28	87.4	11.02	273.1	34.41	87.5	11.02	8.0	1.00	0.084	0.011
	59	34.0	4.28	82.5	10.40	258.0	32.51	82.9	10.44	7.8	0.99	0.079	0.010
	90†	34.0	4.28	75.6	9.53	235.9	29.73	82.0	10.33	7.7	0.97	0.073	0.009
50	20	34.0	4.28	68.2	8.59	210.8	26.57	116.4	14.66	7.7	0.97	0.067	0.008
	59	34.0	4.28	64.9	8.18	200.8	25.30	114.9	14.47	7.7	0.97	0.063	0.008
	90†	34.0	4.28	59.8	7.54	184.7	23.28	136.4	17.19	7.5	0.95	0.058	0.007

Note: Neg. = negligible

*Excludes H_2SO_4 mist.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: GE, 1998.
ECT, 2003.

Table 2-3. Maximum H_2SO_4 Mist Pollutant Emission Rates (per SCCT)

Unit Load (%)	Ambient Temperature (°F)	Natural Gas H_2SO_4 Mist		Distillate Fuel Oil H_2SO_4 Mist	
		lb/hr	g/s	lb/hr	g/s
100	20	1.2	0.15	12.4	1.56
	59	1.1	0.14	11.7	1.47
	90*	1.0	0.13	10.6	1.34
75	20	0.9	0.12	10.0	1.27
	59	0.9	0.11	9.5	1.19
	90*	0.8	0.10	8.7	1.09
50	20	0.7	0.09	7.8	0.99
	59	0.7	0.09	7.5	0.94
	90*	0.7	0.08	6.9	0.87

*Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: GE, 1998.
ECT, 2003.

Table 2-4. Maximum Noncriteria Pollutant Emission Rates for 100-Percent Load and Three Temperatures (per SCCT)—Natural Gas

Unit Load (%)	Ambient Temperatire (°F)	1,3-Butadiene		Acetaldehyde		Acrolein		Benzene		Ethylbenzene		Formaldehyde	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	8.43E-05	1.06E-05	7.84E-03	9.88E-04	1.25E-03	1.58E-04	2.35E-03	2.964E-04	6.27E-03	7.90E-04	1.27E-01	1.60E-02
	59	7.89E-05	9.94E-06	7.34E-03	9.24E-04	1.17E-03	1.48E-04	2.20E-03	2.77E-04	5.87E-03	7.39E-04	1.19E-01	1.50E-02
	90*	7.26E-05	9.15E-06	6.75E-03	8.51E-04	1.08E-03	1.36E-04	2.03E-03	2.55E-04	5.40E-03	6.81E-04	1.10E-01	1.38E-02

Unit Load (%)	Ambient Temperatire (°F)	Naphthalene		Polycyclic Organic Matter		Propylene Oxide		Toluene		Xylene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	2.55E-04	3.21E-05	4.31E-04	5.43E-05	5.68E-03	7.16E-04	2.55E-02	3.21E-03	1.25E-02	1.58E-03
	59	2.38E-04	3.00E-05	4.03E-04	5.08E-05	5.32E-03	6.70E-04	2.38E-02	3.00E-03	1.17E-02	1.48E-03
	90*	2.19E-04	2.77E-05	3.71E-04	4.68E-05	4.90E-03	6.17E-04	2.19E-02	2.77E-03	1.08E-02	1.36E-03

Note: Neg. = negligible

*Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Source: ECT, 2003.

Table 2-5. Maximum Noncriteria Pollutant Emission Rates for 100-Percent Load and Three Temperatures (per SCCT)—Distillate Fuel Oil

Unit Load (%)	Ambient Temperatire (°F)	1,3-Butadiene		Arsenic		Benzene		Beryllium		Cadmium		Chromium	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	3.42E-02	4.31E-03	2.35E-02	2.96E-03	1.18E-01	1.48E-02	6.63E-04	8.35E-05	1.03E-02	1.29E-03	2.35E-02	2.96E-03
	59	3.22E-02	4.06E-03	2.22E-02	2.79E-03	1.11E-01	1.40E-02	6.25E-04	7.87E-05	9.67E-03	1.22E-03	2.22E-02	2.79E-03
	90*	2.93E-02	3.69E-03	2.02E-02	2.54E-03	1.01E-01	1.27E-02	5.68E-04	7.16E-05	8.80E-03	1.11E-03	2.02E-02	2.54E-03

Unit Load (%)	Ambient Temperatire (°F)	Formaldehyde		Lead		Manganese		Mercury		Naphthalene		Nickel	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	5.99E-01	7.54E-02	2.99E-02	3.77E-03	1.69E+00	2.13E-01	2.57E-03	3.23E-04	7.49E-02	9.43E-03	9.84E-03	1.24E-03
	59	5.64E-01	7.11E-02	2.82E-02	3.55E-03	1.59E+00	2.01E-01	2.42E-03	3.05E-04	7.05E-02	8.89E-03	9.27E-03	1.17E-03
	90*	5.13E-01	6.46E-02	2.57E-02	3.23E-03	1.45E+00	1.82E-01	2.20E-03	2.77E-04	6.41E-02	8.08E-03	8.43E-03	1.06E-03

Unit Load (%)	Ambient Temperatire (°F)	PAH		Selenium	
		lb/hr	g/s	lb/hr	g/s
100	20	8.55E-02	1.08E-02	5.35E-02	6.74E-03
	59	8.06E-02	1.02E-02	5.04E-02	6.35E-03
	90*	7.33E-02	9.24E-03	4.58E-02	5.77E-03

Note: Neg. = negligible

*Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Source: ECT, 2003.

Table 2-6. Maximum Annualized Emission Rates for Bayside SC Unit 3 (tpy)

Pollutant	Annualized Emission Rates CT-3A and CT-3B		
	Natural Gas	Distillate Fuel Oil	Total Facility
NO_x	557.0	224.2	781.2
CO	245.6	48.3	293.9
PM/PM_{10}*	145.1	23.8	168.9
SO_2	74.2	68.8	142.9
VOC	24.4	5.4	29.8
H_2SO_4	8.5	7.9	16.4
HAPs			
1,3 Butadiene	6.36E-04	2.26E-02	2.32E-02
Acetaldehyde	5.92E-02		5.92E-02
Acrolein	8.74E-03		8.74E-03
Arsenic		1.55E-02	1.55E-02
Benzene	1.77E-02	7.76E-02	9.53E-02
Beryllium		4.38E-04	4.38E-04
Cadmium		6.78E-03	6.78E-03
Chromium	1.55E-02	1.55E-02	
Ethylbenzene	4.74E-02		4.74E-02
Formaldehyde	9.60E-01	3.94E-01	1.35E+00
Lead		1.97E-02	1.97E-02
Manganese	1.11E+00	1.11E+00	
Mercury	0.00E+00	1.69E-03	1.69E-03
Naphthalene	1.92E-03	4.94E-02	5.13E-02
Nickel		6.48E-03	6.48E-03
PAH	3.26E-03	5.64E-02	5.97E-02
Propylene Oxide	4.28E-02		4.28E-02
Selenium		3.52E-02	3.52E-02
Toluene	1.92E-01		1.92E-01
Xylenes			
Total HAPs	1.33E+00	1.82E+00	3.15E+00

*Excludes H_2SO_4 mist.

Sources: TEC, 2003.
GE, 1998.
ECT, 2003.

through 6 will cease before commercial operation of Bayside SC Unit 3 begins. The net annual change in emissions associated with the elimination of Gannon Units 3 through 6 and the addition of the Bayside Units 1 through 4 (including SC Units 3A and 3B) are shown in Table 2-7.

The exhaust gases from each SCCT will be vented to the atmosphere through separate stacks. Stack parameters for the SCCT Units are provided in Tables 2-8 and 2-9 for natural gas and distillate fuel oil firing, respectively.

Table 2-7. Net Annual Change in Emission Rates (tpy)

Pollutant	F.J. Gannon Units 3 through 6 Net Emissions	Bayside Unit 3 Originally Permitted Emissions	Bayside Unit 3 Currently Proposed Emissions	Bayside Unit 3 Difference in Emissions	Net Change in Emissions	PSD Significant Emission Levels
NO_x	-2,713.7	202.4	781.2	578.9	-1,021.8	40
CO	-609.3	251.4	293.9	42.5	816.0	100
SO_2	-2,573.6	90.4	147.9	57.5	-2,029.6	40
H_2SO_4 mist	-123.1	16.6	17.0	0.4	-33.3	7
PM/PM_{10}	-271.4	88.9	84.4	-4.5	92.0	15
Lead	-1.9	0.25	0.30	0.05	-0.5	0.6
VOC	-78.1	24.5	29.8	5.3	62.1	40

Source: ECT, 2003.

Table 2-8. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Natural Gas

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	114.0	34.7	1,081	856	151.0	46.0	18.8	5.72
	59	114.0	34.7	1,117	876	144.5	44.0	18.8	5.72
	90	114.0	34.7	1,141	889	137.6	41.9	18.8	5.72
75	20	114.0	34.7	1,111	873	122.7	37.4	18.8	5.72
	59	114.0	34.7	1,139	888	119.7	36.5	18.8	5.72
	90	114.0	34.7	1,166	903	115.4	35.2	18.8	5.72
50	20	114.0	34.7	1,160	900	103.9	31.7	18.8	5.72
	59	114.0	34.7	1,184	913	102.0	31.1	18.8	5.72
	90	114.0	34.7	1,200	922	98.8	30.1	18.8	5.72

Note: K = Kelvin.
ft/sec = foot per second.
m/sec = meter per second.

Sources: GE, 1998.
ECT, 2003.

Table 2-9. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Distillate Fuel Oil

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	114.0	34.7	1,067	848	154.8	47.2	18.8	5.72
	59	114.0	34.7	1,098	865	149.0	45.4	18.8	5.72
	90	114.0	34.7	1,130	883	141.1	43.0	18.8	5.72
75	20	114.0	34.7	1,184	913	124.8	38.0	18.8	5.72
	59	114.0	34.7	1,195	919	121.5	37.0	18.8	5.72
	90	114.0	34.7	1,200	922	117.4	35.8	18.8	5.72
50	20	114.0	34.7	1,200	922	104.7	31.9	18.8	5.72
	59	114.0	34.7	1,200	922	103.3	31.5	18.8	5.72
	90	114.0	34.7	1,200	922	100.6	30.7	18.8	5.72

Note: K = Kelvin.
ft/sec = foot per second.
m/sec = meter per second.

Sources: GE, 1998.
ECT, 2003.

3.0 AIR QUALITY STANDARDS AND NEW SOURCE REVIEW APPLICABILITY

3.1 NATIONAL AND STATE AAQS

As a result of the CAAA, EPA has enacted primary and secondary national ambient air quality standards (NAAQS) for six air pollutants (Chapter 40, Part 50, Code of Federal Regulations [CFR]). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also enacted ambient air quality standards (AAQS) (reference Section 62-204.240, F.A.C.). Table 3-1 presents the current national and Florida AAQS.

Areas of the country in violation of NAAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. Bayside is located south of downtown Tampa in Hillsborough County. Hillsborough County is presently designated in 40 CFR 81.310 as unclassifiable (for total suspended particulates [TSPs]; that portion of Hillsborough County which falls within the area of a circle having a centerpoint at the intersection of U.S. Highway 41 South and State Road 60 and a radius of 12 kilometers [km] for SO_2 and for lead; the area encompassed within a radius of 5 km centered on universal transverse mercator [UTM] coordinates: 364.0 km east, 3093.5 km north, zone 17, in the city of Tampa), unclassifiable/attainment (for CO), and unclassifiable or better than national standards (for nitrogen dioxide [NO_2]). EPA had previously revoked the 1-hour ozone standard for all areas of Florida in June 1998 due to adoption of a new 8-hour ozone standard. However, due to litigation involving the new 8-hour ozone standard, on July 5, 2000, EPA reinstated the 1-hour ozone standard for all counties in Florida. Presently, 40 CFR 81.310 designates all counties in Florida, including Hillsborough County, as unclassifiable/attainment with respect to the 1-hour ozone standard.

Table 3-1. National and Florida Air Quality Standards (micrograms per cubic meter [$\mu g/m^3$] unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards		Florida Standards
		Primary	Secondary	
SO_2 (ppmv)	3-hour[1]		0.5	0.5
	24-hour[1]	0.14		0.1
	Annual[2]	0.030		0.02
SO_2	3-hour[1]			1,300
	24-hour[1]			260
	Annual[2]			60
PM_{10}[13]	24-hour[3]	150	150	
	Annual[4]	50	50	
PM_{10}	24-hour[5]			150
	Annual[6]			50
$PM_{2.5}$[11,12]	24-hour[7]	65	65	
	Annual[8]	15	15	
CO (ppmv)	1-hour[1]	35		35
	8-hour[1]	9		9
CO	1-hour[1]			40,000
	8-hour[1]			10,000
Ozone (ppmv)	1-hour[9]	0.12		0.12
	8-hour[10]	0.08	0.08	
NO_2 (ppmv)	Annual[2]	0.053	0.053	0.05
NO_2	Annual[2]			100
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5

[1]Not to be exceeded more than once per calendar year.
[2]Arithmetic mean.
[3]Standard attained when the 99th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.
[4]Arithmetic mean, as determined by 40 CFR 50, Appendix N.
[5]Not to be exceeded more than once per year, as determined by 40 CFR 50, Appendix K.
[6]Standard attained when the expected annual arithmetic mean is less than or equal to the standard, as determined by 40 CFR 50, Appendix K.
[7]Standard attained when the 98th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.
[8]Arithmetic mean, as determined by 40 CFR 50, Appendix N.
[9]Standard attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H.
[10]Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentration is less than or equal to the standard, as determined by 40 CFR 50, Appendix I.
[11]The U.S. Court of Appeals for the District of Columbia Circuit (Circuit Court) held that these standards are not enforceable. American Trucking Association v. EPA, 1999 WL300618 (Circuit Court).
[12]The Circuit Court may vacate standards following briefing. Id.
[13]The Circuit Court held PM_{10} standards vacated upon promulgation of effective $PM_{2.5}$ standards.

Sources: 40 CFR 50.
Section 62-204.240, F.A.C.

Hillsborough County is designated attainment (for ozone, CO, and NO_2) and unclassifiable (for SO_2, PM_{10}, and lead) by Section 62-204.340, F.A.C. Hillsborough County is also classified as an air quality maintenance area for ozone (entire county), for PM (that portion of Hillsborough County which falls within the area of a circle having a centerpoint at the intersection of U.S. Highway 41 South and State Road 60 and a radius of 12 km), and for lead (the area encompassed within a radius of 5 km centered on UTM coordinates: 364.0 km east, 3093.5 km north, zone 17) by Section 62-204.340, F.A.C.

3.2 NONATTAINMENT NSR APPLICABILITY

Bayside is located in Hillsborough County. As previously noted, Hillsborough County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, Bayside SC Unit 3 is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

The existing F.J. Gannon Station is classified as a major facility. A modification to a major facility that has potential net emissions equal to or exceeding the significant emission rates indicated in Section 62-212.400, Table 212.400-2, F.A.C., is subject to PSD NSR.

Net emission rates considering the addition of Bayside Units 1 through 4, and the cessation of operations of Gannon Units 3 through 6, will be below the significant emission rate thresholds, with the exception of CO, VOC, and PM/PM_{10}. Table 3-2 provides comparisons of estimated net emissions in relation to PSD significant emission rate thresholds. As shown in this table, potential emissions of all regulated PSD pollutants, with the exception of CO, VOC, and PM/PM_{10}, are projected to be below the applicable PSD significant emission rate levels. Therefore, Bayside SC Unit 3 qualifies as a major modification to a major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for CO, VOC, and PM/PM_{10} only.

Table 3-2. Projected Emissions Compared to PSD Significant Emission Rates

Pollutant	Project Net Emissions Change* (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	-1,021.8	40	No
CO	816.0	100	Yes
PM	92.0	25	Yes
PM_{10}	92.0	15	Yes
SO_2	-2,029.6	40	No
Ozone/VOC	62.1	40	Yes
Lead	-0.5	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Negligible	3	No
H_2SO_4 mist	-33.3	7	No
Total reduced sulfur (including hydrogen sulfide)	Not present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not present	10	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride)	Not present	40	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5×10^{-6}	No

*Gannon Units 3 through 6 and Bayside Units 1 through 4.

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2003.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY

4.1 METHODOLOGY

The CO, VOC, and PM/PM_{10} BACT analyses were performed in accordance with the EPA top-down method. The first step in the top-down BACT procedure is the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, post-process stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information that were used to identify control alternatives include:

- EPA reasonably available control technology (RACT)/BACT/lowest achievable emission rate (LAER) Clearinghouse (RBLC) via the RBLC Information System database.
- EPA NSR web site.
- EPA Control Technology Center (CTC) web site.
- Recent FDEP BACT determinations for similar facilities.
- Vendor information.
- Environmental Consulting & Technology, Inc. (ECT), experience for similar projects.

Following the identification of available control technologies, the next step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the draft *EPA NSR Workshop Manual* (EPA, 1990a). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

An assessment of energy, environmental, and economic impacts is then performed. The economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) *Air Pollution Control Cost Manual, Sixth Edition* (EPA, 2002). Tables 4-1 and 4-2 summarize specific factors used in estimating capital and annual operating costs, respectively.

Table 4-1. Capital Investment Cost Factors

Cost Item	Factor
Direct Capital Costs (DCC)	
Instrumentation	0.10 × equipment cost
Sales tax	0.06 × equipment cost
Freight	0.05 × equipment cost
Purchased equipment cost (PEC)	Instrumentation + sales tax + freight
Foundations and supports	0.08 × PEC
Handling and erection	0.14 × PEC
Electrical	0.04 × PEC
Piping	0.02 × PEC
Insulation	0.01 × PEC
Painting	0.01 × PEC
Indirect Installation Costs (IIC)	
General facilities	0.05 × DCC
Engineering and home office fees	0.10 × DCC
Process contingency	0.05 × DCC
Project Contingency (PC)	0.15 × (DCC + IIC)
Total Plant Cost (TPC)	DCC + IIC + PC
Other Costs (OC)	
Preproduction cost	0.02 × TPC
Inventory capital	Initial reagent
Total Capital Investment (TCI)	TPC + OC

Source: EPA, 2002.

Table 4-2. Annual Operating Cost Factors

Cost Item	Factor
Total Direct Costs (TDC)	
Maintenance labor and materials	0.015 × TCI
Catalyst replacement	Catalyst replacement cost × future worth factor
Energy penalty	0.2 to 1.0 percent of CT output per inch of pressure drop (dependent on control equipment)
Total Indirect Costs (TIC)	TCI × capital recovery factor
Total Annual Cost (TAC)	TDC + TIC

Source: EPA, 2002.

The fifth and final step is the selection of a BACT emission limitation or a design, equipment, work practice, operational standard, or combination thereof, corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

As indicated in Section 3.3, Table 3-2, projected annual emission rates of CO, VOC, and PM/PM_{10} for Bayside SC Unit 3 exceed the PSD significance rates for these pollutants and, therefore, are subject to BACT analysis. Control technology analyses using the five-step top-down BACT method are provided in Sections 4.3 and 4.4 for PM/PM_{10} and products of incomplete combustion (CO and VOC), respectively.

4.2 FEDERAL AND FLORIDA EMISSION STANDARDS

Pursuant to Rule 62-212.400(5)(b), F.A.C., BACT emission limitations must be no less stringent than any applicable new source performance standards (NSPS) (40 CFR 60), National Emission Standard for Hazardous Air Pollutants (NESHAPs) (40 CFR 61 and 63), or FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

On the federal level, emissions from gas turbines are regulated by NSPS Subpart GG. Subpart GG establishes emission limits for gas turbines that were constructed after October 3, 1977, and that meet any of the following criteria:

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 MMBtu/hr based on the lower heating value (LHV) of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the LHV of the fuel.
- Stationary gas turbines with a manufacturer's rated baseload at International Standards Organization (ISO) standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. Bayside SC Units 3A and 3B qualify as electric utility stationary gas turbines and, therefore, are subject to the NO_x and SO_2 emission limitations of NSPS 40 CFR 60, Subpart GG, 60.332(a)(1) and 60.333, respectively. However, NSPS Subpart GG does not include any emission limitations for PM/PM_{10}, CO, or VOC.

FDEP emission standards for stationary sources are contained in Chapters 62-296, F.A.C., *Stationary Sources—Emission Standards*. Visible emissions are limited to a maximum of 20-percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C., Sections 62-296.401 through 62-296.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTs. Rule 62-204.800(7), F.A.C., incorporates the federal NSPS by reference, including Subpart GG.

Emission standards applicable to sources located in ozone nonattainment and maintenance areas are contained in Section 62-296.500, F.A.C. As mentioned in Section 3.0 of this report, all of Hillsborough County is classified as an air quality maintenance area for ozone. However, Section 62-296.500, F.A.C., does not include any emission limitations for PM/PM_{10} or CO.

Bayside will be located at the existing F.J. Gannon Station south of downtown Tampa in Hillsborough County and, therefore, is situated within the Hillsborough County PM air quality maintenance area. Sections 62-296.701 through 62-296.712, F.A.C., specify PM emission standards for 12 categories of sources; none of these categories are applicable to CTs. In addition, these PM emission standards are not applicable to new PM-emitting sources, such as Bayside SC Unit 3, which will be subject to 40 CFR 52.21 (i.e., PSD NSR). Accordingly, there are no PM air quality maintenance area emission limits that are applicable to Bayside SC Unit 3.

Section 62-204.800, F.A.C., adopts federal NSPS and NESHAPs, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines* is applicable to the Bayside SC Unit 3. However, Subpart GG does not contain any PM/PM_{10} or CO emission limitations. There are no applicable NESHAP requirements.

In summary, there are no federal or state PM/PM_{10} or CO emission limitations applicable to Bayside SC Unit 3.

4.3 BACT ANALYSIS FOR PM/PM_{10}

PM/PM_{10} emissions resulting from the combustion of natural gas is due to the oxidation of ash and sulfur contained in the fuel. Due to their low ash and sulfur contents, natural gas and distillate fuel oil combustion generates inherently low PM/PM_{10} emissions.

4.3.1 POTENTIAL CONTROL TECHNOLOGIES

Available technologies used for controlling PM/PM_{10} include the following:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Fabric filters or baghouses.
- Wet scrubbers.

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principal control device since cyclones are effective in removing only large sized (greater than 10 microns) particles. Particles generated from natural gas combustion are typically less than 1.0 micron in size.

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the electrodes. Collection efficiencies are typically 95 percent for particles smaller than 2.5 microns in size.

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM/PM_{10} is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot (cfm-ft^2). Collection efficiencies are on the order of 99 percent for particles smaller than 2.5 microns in size.

Wet scrubbers remove PM/PM_{10} from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM/PM_{10} must either make contact with a spray droplet or impinge upon a wet surface. In a venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high-pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity, causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets produced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drop for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90 percent for particles smaller than 2.5 microns in size.

While all of these postprocess technologies would be technically feasible for controlling PM/PM_{10} emissions from CTs, none of the previously described control equipment has been applied to CTs because exhaust gas PM/PM_{10} concentrations are inherently low. CTs operate with a significant amount of excess air, which generates large exhaust gas flow rates. The Bayside Units 3 CTs will be fired with natural gas and distillate fuel oil and will generate low PM/PM_{10} emissions in comparison to other fuels due to their low ash and sulfur contents. The minor PM/PM_{10} emissions, coupled with a large volume of exhaust gas, produce extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentrations for Bayside SC Units 3A and 3B at baseload and 59°F are approximately 0.003 and 0.005 grains per dry standard cubic foot (gr/dscf) while firing natural gas and distillate fuel oil, respectively. Exhaust stream PM/PM_{10} concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

4.3.2 PROPOSED BACT EMISSION LIMITATIONS

Recent Florida BACT determinations for natural gas-fired CTs are based on the use of clean fuels and good combustion practice.

Because postprocess stack controls for PM/PM_{10} are not appropriate for SCCTs, the use of good combustion practices and clean fuels is considered to be BACT. Bayside Units 3A and 3B will use the latest combustor technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates. Combustion efficiency, defined as the percentage of fuel completely oxidized in the combustion process, is projected to be greater than 99 percent. The SCCTs will be fired with pipeline-quality natural gas and distillate fuel oil. Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM_{10} concentrations and consistent with recent FDEP BACT determinations for SCCTs, the use of clean fuels (e.g., pipeline-quality natural gas and distillate fuel oil) and efficient combustion design and operation is proposed as BACT for PM/PM_{10}. Tables 4-3 and 4-4 illustrate some recent FDEP PM BACT determinations for natural gas- and fuel oil-fired CTs, respectively. As an indicator of the use of a clean fuel and efficient combustion design and operation, a visible emissions limit of 10-percent opacity is proposed. Table 4-5 summarizes the PM/PM_{10} BACT proposed for Bayside SC Units 3A and 3B.

4.4 BACT ANALYSIS FOR CO AND VOC

CO and VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO and VOC emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emissions of CO and VOC will generally increase during turbine partial load conditions when combustion temperatures are lower. Decreased combustion zone temperature due to the injection of water or steam for NO_x control will also result in an increase in CO and VOC emissions.

Table 4-3. Florida BACT PM Emission Limitation Summary—Natural Gas-Fired CTs

Permit Date	Source Name	Turbine Size		PM Emission Limit		Control Technology
		MW	MMBtu/hr	lb/hr	lb/MMBtu	
08/17/92	Orlando Cogeneration, L.P.	79	857	9.0	0.01	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,214	10.5	0.0134	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	367	(9.0)	0.0245	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	869	7.0	0.0100	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,615	9.0	(0.0056)	Combustion design and clean fuels
09/28/93	Florida Gas Transmission	N/A	32	0.64	N/A	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,755	17.0	0.013	Combustion design and clean fuels
03/07/95	Orange Cogeneration, L.P.	39	388	5.0	(0.013)	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	403	5.0	0.0065	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	971	7.0	(0.0072)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		7.0		Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,468	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,174	—	—	Combustion design and clean fuels
09/28/98	Florida Power Corp. Hines Energy Complex	165	1,757	15.6	(0.0089)	Combustion design and clean fuels
08/98	Santa Rosa Energy Center	167	1,600	(8.2)	0.0051	Combustion design and clean fuels
08/98	FP&L Ft. Myers Plant Repowering	170	1,600	—	—	Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 4-4. Florida BACT PM Emission Limitation Summary—Distillate Fuel Oil-Fired CTs

Permit Date	Source Name	Turbine Size		PM Emission Limit		Control Technology
		MW	MMBtu/hr	lb/hr	lb/MMBtu	
08/17/92	Florida Power Corp. Intercession City	93	1,144	15.0	(0.0131)	Combustion design and clean fuels
		186	2,032	17.0	(0.0084)	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,170	36.8	0.0472	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	371	10.0	0.0323	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	928	15.0	0.0162	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,850	17.0	(0.0092)	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,765	17.0	0.009	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	406	20.0	0.026	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	991	15.0	(0.0151)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		—	—	Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,660	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,236	—	—	Combustion design and clean fuels
09/28/98	Florida Power Corp. Hines Energy Complex	165	1,846	44.8	(0.0243)	Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 4-5. Proposed PM/PM_{10} BACT

Emission Source	Proposed PM/PM_{10} BACT
GE PG7241 (FA) (per SCCT unit)	Exclusive use of clean fuels (i.e., natural gas and distillate fuel oil) Efficient combustion design and operation 10.0-percent opacity (Indicator of efficient combustion design and operation)

Sources: TEC, 2003.
ECT, 2003.

An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in CO and VOC emission rates. Emissions of NO_x and CO are inversely related (i.e., decreasing NO_x emissions will result in an increase in CO emissions). Accordingly, CT vendors have had to consider the competing factors involved in NO_x and CO/VOC formation to develop Units that achieve acceptable emission levels for those pollutants.

4.4.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO and VOC from SCCTs: combustion process design and oxidation catalysts.

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of SCCTs, approximately 99 percent, CO and VOC emissions are inherently low.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO and VOC to carbon dioxide (CO_2) and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for conventional oxidation catalysts is between 650 and 1,150°F. Recently, high temperature oxidation catalysts have been developed that can tolerate higher temperatures (i.e., greater than 1,200°F). Typically, the oxidation catalyst is located within the HRSG where temperatures range from 450 to 1,100°F.

Efficiency of CO and VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO and VOC up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F; higher temperatures on the order of 900°F are needed to oxidize VOC. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst that will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time that is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. For CT applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 to 90 percent for CO. VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency using oxidation catalyst is 50 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies.

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOC. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. The catalyst will further oxidize sulfur compounds that have been oxidized to SO_2 in the combustion process to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing significant amounts of sulfur.

Technical Feasibility

Both SCCT combustor design and oxidation catalyst control systems are considered to be technically feasible for Bayside SC Units 3A and 3B. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO and VOC are provided in the following subsections.

4.4.2 ENERGY AND ENVIRONMENTAL IMPACTS

There are no significant adverse energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO and VOC emissions.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing high sulfur contents. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from SCCTs fired with natural gas and distillate fuel oil.

Because CO and VOC emission rates from SCCTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements (i.e., below the defined PSD significant impact levels for CO). The location of Bayside SC Unit 3 (Hillsborough County) is classified attainment for all criteria pollutants, including CO and ozone. As noted in FDEP's 2000 Air Monitoring Report, there have been no exceedances of the CO AAQSs in Florida during the last 13 years. Maximum CO concentrations for all Florida monitoring sites during 2000 were less than 30 percent of the 35-part-per-million (ppm) 1-hour AAQS, and less than 70 percent of the 9-ppm 8-hour AAQS. From an air quality perspective, the only potential benefit of CO oxidation catalyst is to prevent the possible formation of a localized area with elevated concentrations of CO. The catalyst does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to CO_2. Dispersion modeling of Bayside Units 1 through 4 (including SC Units 3A and 3B) CO emissions indicated that maximum CO impacts, without oxidation catalyst, will be insignificant. The highest, second highest (HSH) 1- and 8-hour average CO impacts were projected to be only 0.7 and 1.7 percent of the Florida and Federal CO AAQS.

The application of oxidation catalyst technology to a gas turbine will result in an increase in back pressure on the CT due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power thereby increasing the unit's heat rate. An oxidation catalyst system for Bayside SC Units 3A and 3B is projected to have a pressure drop across the catalyst bed of approximately 1.1 inch of water. This pressure drop will result in a 0.26-percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 5,261,256 kilowatt-hours (kWh) (17,952 million British thermal Units [MMBtu]) per year at baseload (165 MW) operation and 100-percent capacity factor per SCCT. This energy penalty is equivalent to the use of 35.48 million cubic feet (ft^3)

of natural gas annually based on a natural gas heating value of 1,050 British thermal Units per cubic foot (Btu/ft^3) for both SCCTs. The lost power generation energy penalty, based on a power cost of $0.030/kWh, is $315,675 per year for both SCCTs.

4.4.3 ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using OAQPS factors and the project-specific economic factors provided in Table 4-6. Specific capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 4-7 and 4-8, respectively.

The base case Bayside SC Unit 3 annual CO emission rate (i.e., for both SCCTs) is 293.9 tpy based on SCCT baseload operation at 59°F for 8,060 hr/yr operation gas firing and 700 hr/yr oil firing. The controlled annual CO emission rate, based on 90-percent control efficiency, is 29.4 tpy. The cost effectiveness of oxidation catalyst for CO emissions was determined to be $5,626 per ton of CO removed. Based on the high control costs, use of oxidation catalyst technology to control CO emissions is not considered economically feasible. The economic analysis is considered to be conservative (i.e., underestimate the actual cost effectiveness) since actual SCCT exhaust CO concentrations are expected to be well below the GE guarantees. Table 4-9 summarizes the results of the oxidation catalyst economic analysis.

The base case Bayside SC Unit 3 annual VOC emission rate (i.e., for both SCCTs) is 29.8 tpy based on CT baseload operation at 59°F for 8,060 hr/yr operation gas firing and 700 hr/yr oil firing. The controlled annual VOC emission rate, based on 50-percent control efficiency, is 14.9 tpy. The cost effectiveness of oxidation catalyst for VOC emissions was determined to be $99,878 per ton of VOC removed. Based on the high control costs, use of oxidation catalyst technology to control VOC emissions is not considered economically feasible. Table 4-10 summarizes the results of the oxidation catalyst economic analysis.

Table 4-6. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0*
Control system life	Years	15
Oxidation catalyst life	Years	5
Oxidation catalyst control efficiency	%	90.0*
Electricity cost	$/kWh	0.030*
Labor costs (base rates)	$/hour	
Operator	22.00	
Maintenance	22.00	

*Per FDEP recommendation.

Sources: TEC, 2003.
ECT, 2003.

Table 4-7. Capital Costs for Oxidation Catalyst System (Two SCCTs)

Item	Dollars	EPA Factor
Direct Capital Cost		
Equipment cost	3,215,000	EC
Sales tax	192,900	0.06 × EC
Instrumentation	321,500	0.10 × EC
Freight	160,750	0.05 × EC
Total Purchased Equipment Cost (PEC)	**$3,890,150**	
Installation cost		
Foundations and supports	311,212	0.08 × PEC
Handling and erection	544,621	0.14 × PEC
Electrical	155,606	0.04 × PEC
Piping	77,803	0.02 × PEC
Insulation for ductwork	38,902	0.01 × PEC
Painting	38,902	0.01 × PEC
Total Installation Cost (TIC)	**$1,167,046**	
Total Direct Capital Costs (DCC)	**$5,057,196**	**PEC + TIC**
Indirect Installation Cost		
General facilities	252,860	0.05 × DCC
Engineering and home office fees	505,720	0.10 × DCC
Process contingency	252,860	0.05 × DCC
Total Indirect Installation Cost (IIC)	**$1,011,440**	
Project Contingency (PC)	910,295	0.15 × (DCC + IIC)
Total Plant Cost (TPC)	**$6,978,931**	DCC + IIC + PC
Preproduction cost (PPC)	139,579	0.02 × TPC
Total Capital Investment (TCI)	**$7,118,510**	TPC + PPC

Source: ECT, 2003.

Table 4-8. Annual Operating Costs for Oxidation Catalyst System (Two SCCTs)

Item	Dollars	EPA Factor
Direct Cost		
Maintenance labor and materials (ML&M)	106,778	0.015 × TCI
Catalyst replacement cost		
Replacement (materials and labor)	1,889,112	
Credit for used catalyst	255,000	
Total Catalyst Replacement Cost (CRC)	**$1,634,112**	
Future worth factor (FWF)	0.1739	7.0%, 3 yrs
Annualized Catalyst Cost (ACC)	**$284,157**	CRC × FWF
Energy penalty (EP)		
Turbine backpressure	315,675	0.26% / inch delta P
Total Direct Costs (TDC)	**$706,610**	ML&M + ACC + EP
Indirect Cost		
Capital recovery factor (CRF)	0.1098	7.0%, 15 yrs
Capital recovery	781,574	CRF × TCI
Total Indirect Cost (TINC)	**$781,574**	
Total Annual Cost (TAC)	**$1,488,184**	**TDC + TIC**

Source: ECT, 2003.

Table 4-9. Summary of CO BACT Analysis

Control Option	Emission Impacts: Emission Rates lb/hr	Emission Impacts: Emission Rates tpy	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Environmental Impact (Y/N)
Oxidation catalyst	6.7	29.4	264.5	7,118,510	1,488,184	5,626	33,340	Y	Y
Baseline	67.1	293.9	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) SCCTs, 100-percent load, 59°F ambient temperature, 8,060 hr/yr gas-fired, 700 hr/yr oil-fired.

Sources: GE, 1998.
ECT, 2003.

Table 4-10. Summary of VOC BACT Analysis

Control Option	Emission Impacts: Emission Rates lb/hr	Emission Impacts: Emission Rates tpy	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Environmental Impact (Y/N)
Oxidation catalyst	3.4	14.9	14.9	7,118,510	1,488,184	99,878	33,340	Y	Y
Baseline	6.8	29.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) SCCTs, 100-percent load, 59°F ambient temperature, 8,060 hr/yr gas-fired, 700 hr/yr oil-fired.

Sources: GE, 1998.
ECT, 2003.

4.4.4 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO or VOC from SCCTs is typically required only for facilities located in CO or ozone nonattainment areas. Recent summaries of FDEP CO BACT determinations for natural gas- and distillate oil-fired CTs are provided in Tables 4-11 and 4-12, respectively. Similar summaries of recent FDEP VOC BACT determinations for natural gas- and distillate oil-fired CTs are provided in Tables 4-13 and 4-14, respectively.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from SCCTs fired with natural gas and low-sulfur distillate fuel oil. Because CO and VOC emission rates from SCCTs are inherently low, further reductions through the use of oxidation catalysts will result in only minor improvement in air quality (i.e., well below the defined PSD significant impact levels for CO and VOC).

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion is proposed as BACT for CO. These control techniques have been considered by FDEP to represent BACT for CO and VOC for recent SCCT projects, as shown in Tables 4-11 to 4-14.

Maximum CO exhaust concentrations from Bayside SC Units 3A and 3B will be less than or equal to 7.8 and 30.3 ppmvd for natural gas and distillate fuel oil firing, respectively. These CO exhaust concentrations are consistent with recent FDEP CO BACT determinations for SCCT Units (see Tables 4-11 and 4-12).

Maximum VOC exhaust concentrations from Bayside SC Units 3A and 3B will be less than or equal to 1.2 and 3.0 ppmvd for natural gas and distillate fuel oil firing, respectively. These VOC exhaust concentrations are consistent with recent FDEP VOC BACT determinations for SCCT Units (see Tables 4-13 and 4-14).

Table 4-11. Florida BACT CO Summary—Natural Gas-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40	30	Good combustion
04/09/93	Kissimmee Utility Authority	80	20	Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	15	Good combustion
02/21/94	Polk Power Partners	84	25	Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260	25	Good combustion
07/20/94	Pasco Cogen, Limited	42	28	Good combustion
03/07/95	Orange Cogeneration, L.P.	39	30	Good combustion
06/01/95	Panda-Kathleen	75	25	Good combustion
09/28/95	City of Key West	23	20	Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20	Good combustion
05/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	25	Good combustion
08/99	Santa Rosa Energy Center	167	9	Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 4-12. Florida BACT CO Summary—Distillate Fuel Oil-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40	63	Good combustion
04/09/93	Kissimmee Utility Authority	80	20	Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	30	Good combustion
02/21/94	Polk Power Partners	84	35	Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260	40	Good combustion
07/20/94	Pasco Cogen, Limited	42	18	Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	25	Good combustion
05/98	City of Tallahassee Purdom Unit 8	160	90	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	90	Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	30	Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 4-13. Florida BACT VOC Summary—Natural Gas-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit ppmvd	VOC Emission Limit lb/MmBtu	Control Technology
02/21/94	Polk Power Partners	84	25		Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260		0.0017	Good combustion
07/20/94	Pasco Cogen, Limited	42	28		Good combustion
03/07/95	Orange Cogeneration, L.P.	39	10		Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20		Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	4		Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	7		Good combustion
08/99	Santa Rosa Energy Center	167	1.4		Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 4-14. Florida BACT VOC Summary—Distillate Fuel Oil-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit ppmvd	VOC Emission Limit lb/MmBtu	Control Technology
02/21/94	Polk Power Partners	84	25		Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260		0.0128	Good combustion
07/20/94	Pasco Cogen, Limited	42	28		Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20		Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	10		Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	10		Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

CO BACT emission limits proposed for Bayside SC Units 3A and 3B are provided in Table 4-15. The CO BACT limits shown in Table 4-15 are consistent with the limits recently approved by FDEP for Bayside Units 1 and 2. VOC BACT emission limits proposed for Bayside SC Units 3A and 3B are provided in Table 4-16.

Table 4-15. Proposed CO BACT Emission Limits

Emission Source	Proposed CO BACT Emission Limits	
	ppmvd*	lb/hr†
GE PG7241 (FA) SCCT (per SCCT)		
CO (natural gas)	7.8	33.0
CO (distillate fuel oil)	30.3	136.4

*Corrected to 15-percent oxygen.
†CT compressor inlet air temperature of 59°F.

Sources: TEC, 2003.
ECT, 2003.

Table 4-16. Proposed VOC BACT Emission Limits

Emission Source	Proposed VOC BACT Emission Limits ppmvd*	lb/hr†
GE PG7241 (FA) SCCTs (per SCCT)		
VOC (natural gas)	1.2	3.0
VOC (distillate fuel oil)	3.0	8.0

*Corrected to 15-percent oxygen.
†CT compressor inlet air temperature of 59°F.

Sources: TEC, 2003.
ECT, 2003.

5.0 AMBIENT IMPACT ANALYSIS METHODOLOGY

5.1 GENERAL APPROACH

The approach used to analyze the potential impacts of the proposed facility, as described in detail in the following sections, was developed in accordance with accepted practice. Guidance contained in EPA manuals and user's guides was sought and followed.

5.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, Bayside SC Units 3A and 3B will have the potential to emit 781.2 tpy of NO_x, 293.9 tpy of CO, 168.9 tpy of PM/PM_{10}, 147.9 tpy of SO_2, 29.8 tpy of VOCs, and 17.0 tpy of H_2SO_4 mist. Table 3-2 previously provided estimated potential annual emission rates increases for the Gannon/Bayside repowering project. As shown in that table, potential emission increases of all PSD regulated pollutants will be below the applicable PSD significant emission rate levels, with the exception of CO, PM, and PM_{10}. Accordingly, Bayside SC Units 3A and 3B are subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C., for CO and PM/PM_{10} only. In response to a prior request from FDEP, an air quality impact analysis for Bayside SC Units 3A and 3B was also conducted for NO_2 and SO_2.

5.3 MODEL SELECTION AND USE

For this study, air quality modeling was applied at the refined level. Refined modeling requires more detailed and precise input data than screening modeling, but is presumed to have provided more accurate estimates of source impacts.

The most recent regulatory version of the Industrial Source Complex (ISC3) models (EPA, 2000) is recommended and was used in this analysis for refined modeling. The ISC3 models are steady-state Gaussian plume models that can be used to assess air quality impacts over simple terrain from a wide variety of sources. The ISC3 models are capable of calculating concentrations for averaging times ranging from 1 hour to annual. For this study, the ISC3 short-term (ISCST3) (Version 00101) model was used to calculate short-term ambient impacts with averaging times between 1 and 24 hours as well as long-term annual averages.

Procedures applicable to the ISCST3 dispersion model specified in EPA's Guideline for Air Quality Models (GAQM) were followed in conducting the refined dispersion modeling. The GAQM is codified in Appendix W of 40 CFR 51. In particular, the ISCST3 model control pathway MODELOPT keyword parameters DFAULT, CONC, RURAL, and NOCMPL were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC, RURAL, and NOCMPL parameters specify calculation of concentrations, use of rural dispersion, and suppression of complex terrain calculations, respectively. As previously mentioned, the ISCST3 model was also used to determine annual average impact predictions, in addition to short-term averages, by using the PERIOD parameter for the AVERTIME keyword. Conservatively, no consideration was given to pollutant exponential decay.

5.4 NO_2 AMBIENT IMPACT ANALYSIS

For annual NO_2 impacts, the tiered screening approach described in the GAQM, Section 6.2.3, was used. Tier 1 of this screening procedure assumes complete conversion of NO_x to NO_2. Tier 2 applies an empirically derived NO_2/NO_x ratio of 0.75 to the Tier 1 results.

5.5 DISPERSION OPTION SELECTION

Area characteristics in the vicinity of proposed emission sources are important in determining model selection and use. One important consideration is whether the area is rural or urban since dispersion rates differ between these two classifications. In general, urban areas cause greater rates of dispersion because of increased turbulent mixing and buoyancy-induced mixing. This is due to the combination of greater surface roughness caused by more buildings and structures and greater amount of heat released from concrete and similar surfaces. EPA guidance provides two procedures to determine whether the character of an area is predominantly urban or rural. One procedure is based on land use typing, and the other is based on population density. The land use typing method uses the work of Auer (Auer, 1978) and is preferred by EPA and FDEP because it is meteorologically oriented. In other words, the land use factors employed in making a rural/urban designation are also factors that have a direct effect on atmospheric dispersion. These factors include building types, extent of vegetated surface area and water surface area, types of industry and commerce, etc. Auer recommends these land use factors be considered within 3 km of the source to be modeled to determine urban or rural classifications. The Auer land use typing method was used for the ambient impact analysis.

The Auer technique recognizes four primary land use types: industrial (I), commercial (C), residential (R), and agricultural (A). Practically all industrial and commercial areas come under the heading of urban, while the agricultural areas are considered rural. However, those portions of generally industrial and commercial areas that are heavily vegetated can be considered rural in character. In the case of residential areas, the delineation between urban and rural is not as clear. For residential areas, Auer subdivides this land use type into four groupings based on building structures and associated vegetation. Accurate classification of the residential areas into proper groupings is important to determine the most appropriate land use classification for the study area.

USGS 7.5-minute series topographic maps for the area were used to identify the land use types within a 3-km radius area of the proposed site. Based on this analysis, more than 50 percent of the land use surrounding the plant was determined to be rural under the Auer land use classification technique. Therefore, rural dispersion coefficients and mixing heights were used for the ambient impact analysis.

5.6 TERRAIN CONSIDERATION

The GAQM defines flat terrain as terrain equal to the elevation of the stack base, simple terrain as terrain lower than the height of the stack top, and complex terrain as terrain above the height of the plume centerline (for screening modeling, complex terrain is terrain above the height of the stack top). Terrain above the height of the stack top, but below the height of the plume centerline, is defined as intermediate terrain.

USGS 7.5-minute series topographic maps were examined for terrain features in the vicinity of Bayside (i.e., within an approximate 10-km radius). Review of the USGS topographic maps indicates nearby terrain would be classified as simple terrain. Due to the minimal amount of terrain elevation differences in the vicinity, assignment of receptor terrain elevations was not conducted (i.e., all receptors were assumed to be at the same elevation as the SCCT stack bases for modeling purposes).

5.7 GOOD ENGINEERING PRACTICE (GEP) STACK HEIGHT/BUILDING WAKE EFFECTS

According to EPA regulations (40 CFR 51), GEP stack height is defined as the highest of 65 meters or a height established by applying the formula:

$$Hg = H + 1.5\ L$$

where: Hg = GEP stack height.

H = height of the structure or nearby structure.

L = lesser dimension (height or projected width) of the nearby structure.

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. While the GEP stack height regulations require that stack heights used in modeling for determining compliance with NAAQS and PSD increments not exceed GEP stack heights, the actual stack height may be greater. Guidelines for determining GEP stack height have been issued by EPA (1985).

The stack height proposed for the Bayside SC Units 3A and 3B (126.5 feet [ft]) is less than the *de minimis* GEP height of 65 meters (213 ft) and, therefore, complies with the EPA promulgated final stack height regulations (40 CFR 51).

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. The ISC3 dispersion models contain two algorithms that assess the effect of building downwash; these algorithms are referred to as the Huber-Snyder and Schulman-Scire methods. The following steps are employed in determining the effects of building downwash:

- A determination is made as to whether a particular stack is located in the area of influence of a building (i.e., within five times the lesser of the building's height or projected width). If the stack is not within this area, it will not be subject to downwash from that building.
- If a stack is within a building's area of influence, a determination is made as to whether it will be subject to downwash based on the heights of the stack and building. If the stack height to building height ratio is equal to or greater than 2.5, the stack will not be subject to downwash from that building.
- If both conditions in the previous two items are satisfied (i.e., a stack is within the area of influence of a building and has a stack height to building height ratio of less than 2.5), the stack will be subject to building downwash. The determination is then made as to whether the Huber-Snyder or Schulman-Scire downwash method applies. If the stack height is less than or equal to the building height plus one-half the lesser of the building height or width, the Schulman-Scire method is used. Conversely, if the stack height is greater than this criterion, the Huber-Snyder method is employed.
- The ISCST3 downwash input data consists of an array of 36 wind direction-specific building heights and projected widths for each stack. LB is defined as the lesser of the height and projected width of the building. For directionally dependent building downwash, wake effects are assumed to occur if a stack is situated within a rectangle composed of two lines perpendicular to the wind direction, one line at 5 LB downwind of the building and the other at 2 LB upwind of the building, and by two lines parallel to the wind, each at 0.5 LB away from the side of the building.

Table 5-1 provides dimensions of the building/structures evaluated for wake effects.

5.8 RECEPTOR GRIDS

Receptors were placed at locations considered to be ambient air, which is defined as "that portion of the atmosphere, external to buildings, to which the general public has access."

Table 5-1. Building/Structure Dimensions (meters)

Building/Structure	Dimensions		
	Width	Length	Height
Boiler 1 structure	17.1	21.0	44.8
Boiler 2 structure	15.8	17.1	45.1
Boiler 3 structure	17.1	22.9	45.1
Boiler 4 structure	17.1	21.9	48.8
Boiler 5 structure	17.1	18.9	53.0
Boiler 6 structure	17.1	23.8	62.2
Tripper structure	17.1	185.0	50.3
Steam turbine structure	27.1	191.1	29.0
CT 3A-4B HRSGs	21.3	27.4	28.9
SCCT 3A, 3B inlet air filter	9.9	18.3	21.3

Sources: TEC, 2003.
ECT, 2003.

The entire perimeter of the Gannon/Bayside plant site is fenced. Therefore, the nearest locations of general public access are at the facility fence lines.

The receptor grids were formulated consistent with GAQM recommendations. Discrete receptors were placed on the restricted area boundaries. Additional discrete receptors were placed at 10-degree (°) increments, beginning at 10° on rings at 250 and 500 meters if the specific polar receptor was an ambient air location. Complete rings with receptors located at 10° increments, beginning at 10°, were located at 250-meter increments from 750 to 7,000 meters and at 8,000; 9,000; 10,000; and 12,000 meters. These receptor grids are consistent with prior Gannon/Bayside dispersion modeling studies submitted to FDEP.

Figure 5-1 illustrates a graphical representation of the receptor grids (out to a distance of 1,500 meters). A depiction of the receptor grids (from 1,500 meters to 12 km) is shown in Figure 5-2.

5.9 METEOROLOGICAL DATA

Detailed meteorological data are needed for modeling with the ISC3 dispersion models. The ISCST3 model requires a preprocessed data file compiled from hourly surface observations and concurrent twice-daily rawinsonde soundings (i.e., mixing height data).

Consistent with the GAQM and FDEP guidance, modeling should be conducted using the most recent, readily available, 5 years of meteorological data collected at a nearby observation station. In accordance with this guidance, the selected meteorological dataset consisted of St. Petersburg/Clearwater International Airport (SPG), Station ID 72211, surface data and Ruskin (RUS), Station ID 12842, upper air data. These data were obtained from the National Climatic Data Center (NCDC) for the 1992 through 1996 5-year period.

The surface and mixing height data for each of the 5 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.

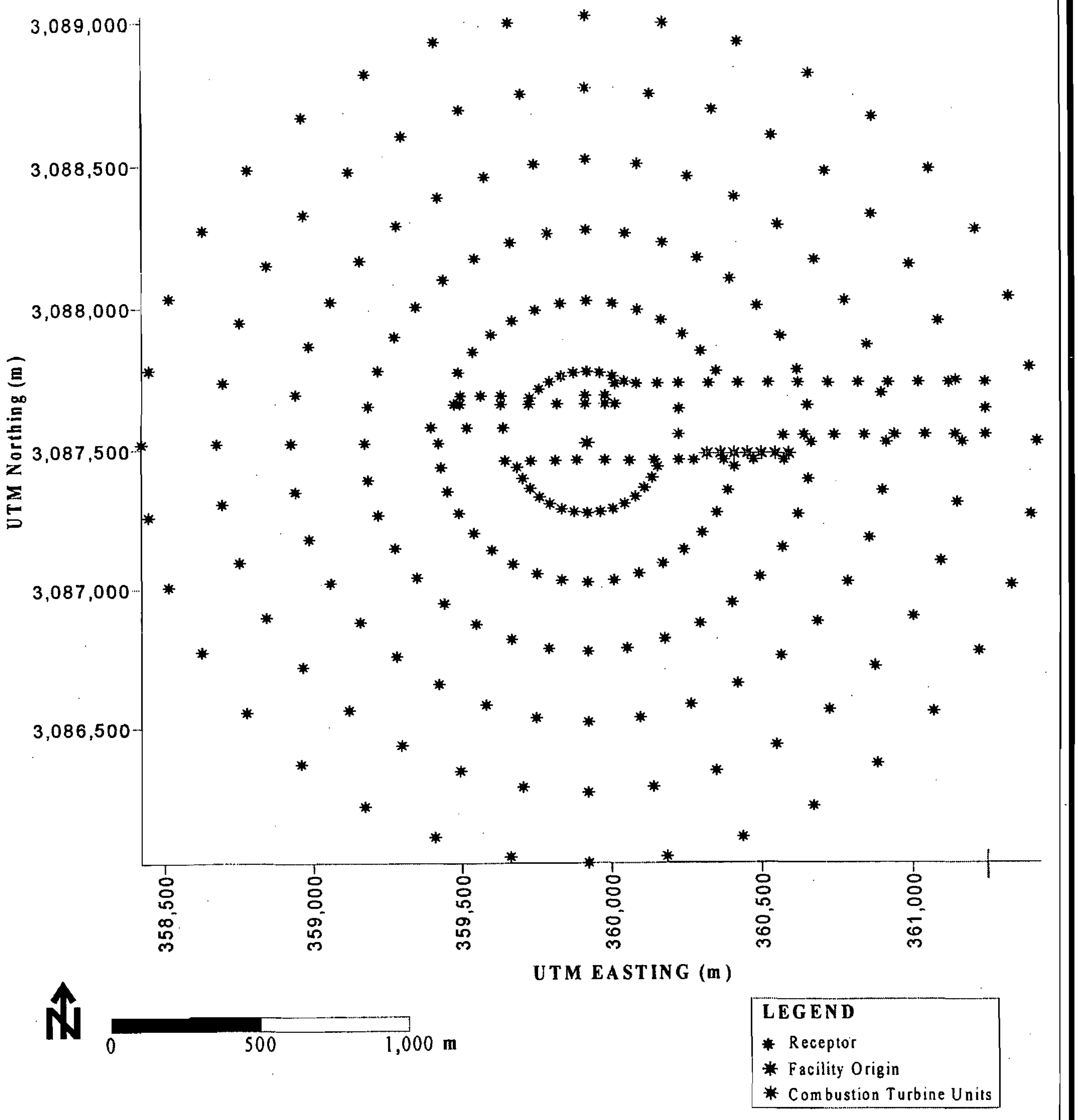

FIGURE 5-1.

RECEPTOR LOCATIONS (WITHIN 1,500 METERS)

Source: ECT, 2003.

TECO
TAMPA ELECTRIC

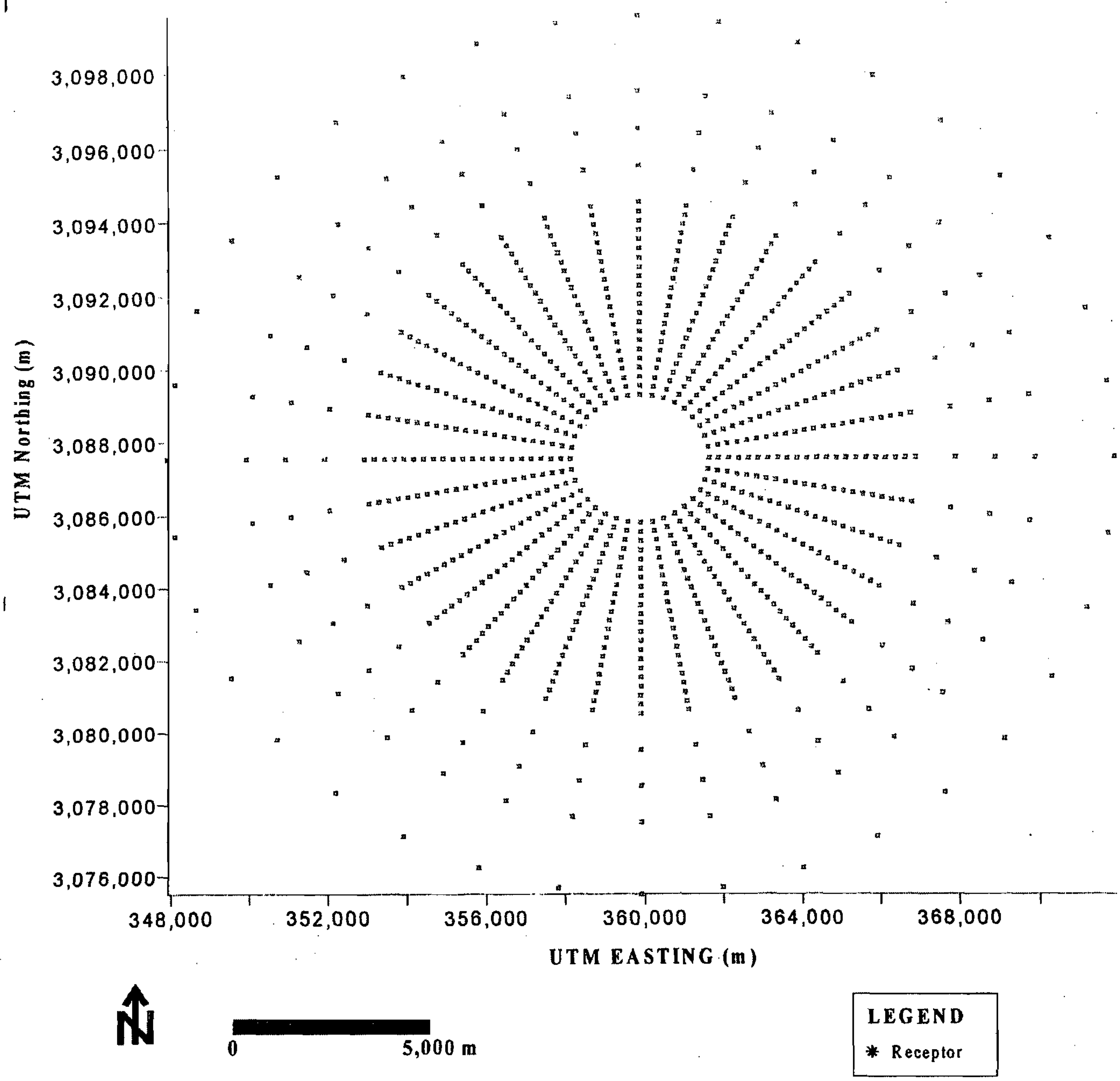

FIGURE 5-2.

RECEPTOR LOCATIONS (FROM 1,500 METERS TO 12 KM)

Source: ECT, 2003.

TECO
TAMPA ELECTRIC

5.10 MODELED EMISSION INVENTORY

As requested by FDEP, the modeled on-property emission sources consisted of the 11 Bayside Units 1 through 4. Refined modeling was conducted for each of the nine operating cases.

Emission rates and stack parameters for the Bayside SC Units 3A and 3B were previously presented in Tables 2-1 and 2-6.

6.0 AMBIENT IMPACT ANALYSIS RESULTS

The refined ISCST3 model was used to model each of the nine Bayside Units 1 through 4 operating scenarios. For SC Units 3A and 3B, short-term (i.e., 1-, 3-, 8-, and 24-hour) and long-term (i.e., annual) impacts were conservatively based on continuous oil firing. These operating scenarios include three loads (50, 75, and 100 percent) and three ambient temperatures (20, 59, and 90°F). Table 6-1 summarizes ISCST3 model results for each year of meteorology evaluated (1992 through 1996) for SO_2, NO_2, PM/PM_{10}, and CO impacts.

Maximum HSH 3- and 24-hour SO_2 impacts are projected to be 217.1 and 56.4 $\mu g/m^3$, respectively. The 3-hour HSH SO_2 impact is 16.7 percent of the Federal and Florida 3-hour average AAQS of 1,300 $\mu g/m^3$. The 24-hour HSH SO_2 impact is 15.4 and 21.7 percent of the Federal and Florida 24-hour average AAQS of 365 and 260 $\mu g/m^3$, respectively. Maximum annual average SO_2 impact is projected to be 2.5 $\mu g/m^3$. This impact is 3.1 and 4.2 percent of the Federal and Florida annual average AAQS of 80 and 60 $\mu g/m^3$, respectively.

Maximum annual average NO_2 impact is projected to be 5.1 $\mu g/m^3$. This impact is 5.1 percent of the Federal and Florida annual average AAQS of 100 $\mu g/m^3$.

Maximum HSH 24-hour PM/PM_{10} impact is projected to be 52.6 $\mu g/m^3$. This impact is 35.1 percent of the 24-hour Federal and Florida AAQS of 150 $\mu g/m^3$. Maximum annual average PM/PM_{10} impact is projected to be 3.6 $\mu g/m^3$. This impact is 7.2 percent of the Federal and Florida annual average AAQS of 50 $\mu g/m^3$.

Maximum HSH 1- and 8-hour CO impacts are projected to be 696.6 and 224.8 $\mu g/m^3$, respectively. These impacts are 1.7 and 2.2 percent of the Federal and Florida 1- and 8-hour average AAQS of 40,000 and 10,000 $\mu g/m^3$, respectively.

APPENDIX A

APPLICATION FOR AIR PERMIT
TITLE V SOURCE

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

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I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Tampa Electric Company**	
2. Site Name: **Bayside Power Station**	
3. Facility Identification Number: **0570040**	
4. Facility Location...: Street Address or Other Locator: **Port Sutton Road** City: **Tampa** County: **Hillsborough** Zip Code: **33619**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☐ Yes ☒ No

Application Contact

1. Application Contact Name: **Dru Latchman**
2. Application Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **6499 U.S. Highway 41 North** City: **Apollo Beach** State: **FL** Zip Code: **33572-9200**
3. Application Contact Telephone Numbers... Telephone: **(813) 641-5358** ext. Fax: **(813) 641-5081**
4. Application Contact Email Address: **dlatchman@tecoenergy.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	7-22-03
2. Project Number(s):	0570040-019-AC
3. PSD Number (if applicable):	PSD-FL-301B
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

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

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

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

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

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

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

Application Comment

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
026	Simple Cycle Combustion Turbine Unit 3A	AC1A	$7,500
027	Simple Cycle Combustion Turbine Unit 3B	AC1A	

Application Processing Fee

Check one: ☒ Attached - Amount: $ 7,500 ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name :
   Wade A. Maye, General Manager, F.J. Gannon Station

2. Owner/Authorized Representative Mailing Address...
   Organization/Firm: **Tampa Electric Company**
   Street Address: **Port Sutton Road**
   City: **Tampa** State: **FL** Zip Code: **33619**

3. Owner/Authorized Representative Telephone Numbers...
   Telephone: **(813) 641-5400** ext. Fax: **(813) 641-5418**

4. Owner/Authorized Representative Email Address: **wmaye@tecoenergy.com**

5. Owner/Authorized Representative Statement:

   I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.

   ____________________ ______________
   Signature Date

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name :
   Wade A. Maye, General Manager, F.J. Gannon Station
2. Owner/Authorized Representative Mailing Address...
   Organization/Firm: **Tampa Electric Company**
   Street Address: **Port Sutton Road**
   City: **Tampa** State: **FL** Zip Code: **33619**
3. Owner/Authorized Representative Telephone Numbers...
   Telephone: **(813) 641-5400** ext. Fax: **(813) 641-5351**
4. Owner/Authorized Representative Email Address: **wamaye@tecoenergy.com**
5. Owner/Authorized Representative Statement:

   I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.

   WAMaye — Signature

   7/21/03 — Date

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APPLICATION INFORMATION

Application Responsible Official Certification

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

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ext. Fax:
5. Application Responsible Official Email Address:
6. Application Responsible Official Certification: *I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.* Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address... Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **FL** Zip Code: **32606**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 332-0444** ext. Fax: **(352) 332-6722**
4.	Professional Engineer Email Address: **tdavis@ectinc.com**
5.	Professional Engineer Statement:

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

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

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

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

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

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

Signature

July 21, 2003
Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) **360.00** North (km) **3,087.5**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Dru Latchman, Environmental Coordinator**
2. Facility Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **Port Sutton Road** City: **Tampa** State: **FL** Zip Code: **33619**
3. Application Contact Telephone Numbers... Telephone: **(813) 641-5358** ext. Fax: **(813) 641-5081**
4. Application Contact Email Address: **dlatchman@tecoenergy.com**

Facility Primary Responsible Official

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

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

FACILITY INFORMATION

Facility Regulatory Classifications

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

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

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOx	**A**	
CO	**A**	
PM	**A**	
PM10	**A**	
SO2	**A**	
SAM	**A**	
VOC	**A**	
PB	**B**	
HAPs	**B**	

B. EMISSIONS CAPS N/A

Facility-Wide or Multi-Unit Emissions Caps

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-2** ☐ Previously Submitted, Date:_____
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-4** ☐ Previously Submitted, Date:_____
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) **N/A** ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID: **Fig 2-1** ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification: ☒ Attached, Document ID: **See Section 2.0**
3. Rule Applicability Analysis: ☒ Attached, Document ID: **Appendix A-2**
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☒ Attached, Document ID: **Sections 5.0, 6.0** ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable

Additional Requirements for FESOP Applications N/A

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.) ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit. ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one) ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent). ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions. ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.				
2. Description of Emissions Unit Addressed in this Section: **Simple cycle combustion turbine Unit 3A.**				
3. Emissions Unit Identification Number: **3A**				
4. Emissions Unit Status Code: **Type C**	5. Commence Construction Date: **October, 2004**	6. Initial Startup Date: **October 2005**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? ☒ Yes ☐ No
9. Package Unit: Manufacturer: **General Electric** Model Number: **PG7241(FA)**				
10. Generator Nameplate Rating: **165 MW**				

11. Emissions Unit Comment: **Simple cycle combustion turbine**

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **NOx Controls: Dry low_NOx combustors (DLN) and water injection (WI)**	
2. Control Device or Method Code(s): **025 (DLN), 028 (WI)**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1.	Maximum Process or Throughput Rate: **165 MW (per SCCT)**
2.	Maximum Production Rate: **8,760 hours per year**
3.	Maximum Heat Input Rate: **1,834 (gas), 2,015 (oil)** million Btu/hr
4.	Maximum Incineration Rate: pounds/hr tons/day
5.	Requested Maximum Operating Schedule: **24** hours/day **7** days/week **52** weeks/year **8760** hours/year
6.	Operating Capacity/Schedule Comment: **Maximum heat input is higher heating value (HHV) at 100 percent load, 59 degrees F, and the natural gas firing (i.e., the primary fuel). The maximum heat input for distillate fuel oil firing is 2,015 MMBtu/hr HHV at 59 degrees F. Heat input will vary with load and ambient temperature.**

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Unit 3A**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: V	6. Stack Height: **114.0** feet	7. Exit Diameter: **18.8** feet
8. Exit Temperature: **1,120** °F	9. Actual Volumetric Flow Rate: **2,393,587** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack temperature and flow rate are for 100 percent load, 59 degrees F, and natural gas firing. For the same operating conditions and distillate fuel oil firing,the exhaust temperature is 1,100 degrees F, and the volumetric flow rates would be 2,468,510 acfm at 11.19 percent water vapor, and 742,956 dscfm.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with pipeline quality natural gas (8,760 hours per year).**		
2. Source Classification Code (SCC): **20100202**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.790**	5. Maximum Annual Rate: **15,680**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2 grains/100 scf**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,022**
10. Segment Comment:		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with distillate fuel oil (700 hours per year maximum).**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **Thousand gallons burned**	
4. Maximum Hourly Rate: **13.889**	5. Maximum Annual Rate: **9,722**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05 by weight**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **137.6**
10. Segment Comment:		

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

Segment Description and Rate: Segment _____ of _____

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

Segment Description and Rate: Segment _____ of _____

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	**025**	**028**	**EL**
CO			**EL**
PM			**EL**
PM10			**EL**
SO2			**EL**
VOC			**EL**

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **NOX**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10.5 ppm (gas), 42 ppm (oil)**	4. Equivalent Allowable Emissions: **69.1** lb/hour **781.2** tons/year
5. Method of Compliance: **EPA Reference Method 7E (initial), NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **CO**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **7.8 ppm (gas), 30.3 ppm (oil) max**	4. Equivalent Allowable Emissions: **69.1** lb/hour **293.9** tons/year
5. Method of Compliance: **EPA Reference Method 10 (initial), CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **PM/PM10**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **18.0 lb/hr (gas), 34.0 lb/hr (oil),**	4. Equivalent Allowable Emissions: **34.0** lb/hour **168.9** tons/year
5. Method of Compliance: **Exlusive firing of pipline quality natural gas and distillate fuel oil along with efficient combustion indicated by compliance with CO visible emission standards.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **SO2**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10.2 lb/hr (gas), 107.8 lb/hr (oil)**	4. Equivalent Allowable Emissions: **107.8** lb/hour **147.9** tons/year
5. Method of Compliance: **Exclusive firing of pipeline quality natural gas and low sulfur fuel oil.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **VOC**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.2 ppm (gas), 3.0 ppm (oil) max**	4. Equivalent Allowable Emissions: **8.0** lb/hour **29.8** tons/year
5. Method of Compliance: **Exclusive firing of pipeline quality natural gas and low sulfur fuel oil. Compliance with CO emission limits used as surrogate compliance for VOC**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10%** Exceptional Conditions: **20%** Maximum Period of Excess Opacity Allowed: **60 min/hour**	
4. Method of Compliance: EPA Method 9.	
5. Visible Emissions Comment: **Opacity during startup shutdown shall not exceed 10%, except of up to ten 6-minute periods in a calendar day during which the opacity shall not exceed 20%.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **To be provided** Model Number: **To be provided**	Serial Number: **To be provided**
5. Installation Date: **To be provided**	6. Performance Specification Test Date: **To be provided**
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program)** **Specific CEMS information will be provided to FDEP when available.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **O2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **To be provided** Model Number: **To be provided**	Serial Number: **To be provided**
5. Installation Date: **To be provided**	6. Performance Specification Test Date: **To be provided**
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program)** **Specific CEMS information will be provided to FDEP when available.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor _____ of _____

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

Continuous Monitoring System: Continuous Monitor _____ of _____

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-4** ☐ Previously Submitted, Date _____
2.	Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Appendix A-1** ☐ Previously Submitted, Date _____
3.	Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Section 4.0** ☐ Previously Submitted, Date _____
4.	Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable **(construction application)**
5.	Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable

6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ _____ ☐ To be Submitted, Date (if known):__________ Test Date(s)/Pollutant(s) Tested: _____ _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.	
7. Other Information Required by Rule or Statute ☒ Attached, Document ID: _____	☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☒ Attached, Document ID: **Section 4.0** ☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☒ Attached, Document ID: **Section 5.0** ☐ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

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

5. Acid Rain Part Application

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

Additional Requirements Comment

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-2** ☐ Previously Submitted, Date:_____
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-4** ☐ Previously Submitted, Date:_____
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) **N/A** ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **Fig 2-1** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: ☒ Attached, Document ID: **See Section 2.0**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **Appendix A-2**
4.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☒ Attached, Document ID: **Sections 5.0, 6.0** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications N/A

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   Simple cycle combustion turbine Unit 3B.

3. Emissions Unit Identification Number: **3B**

4. Emissions Unit Status Code: **Type C**	5. Commence Construction Date: **May, 2005**	6. Initial Startup Date: **May 2006**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? ☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **General Electric** Model Number: **PG7241(FA)**

10. Generator Nameplate Rating: **165 MW**

11. Emissions Unit Comment: **Simple cycle combustion turbine**

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **NOx Controls: Dry low_NOx combustors (DLN) and water injection (WI)**
2. Control Device or Method Code(s): **025 (DLN), 028 (WI)**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **165 MW (per SCCT)**		
2. Maximum Production Rate: **8,760 hours per year**		
3. Maximum Heat Input Rate: **1,834 (gas), 2,015 (oil)** million Btu/hr		
4. Maximum Incineration Rate: pounds/hr	tons/day	
5. Requested Maximum Operating Schedule:	**24** hours/day	**7** days/week
	52 weeks/year	**8760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input is higher heating value (HHV) at 100 percent load, 59 degrees F, and the natural gas firing (i.e., the primary fuel). The maximum heat input for distillate fuel oil firing is 2,015 MMBtu/hr HHV at 59 degrees F. Heat input will vary with load and ambient temperature.**		

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Unit 3B**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: V	6. Stack Height: **114.0** feet	7. Exit Diameter: **18.8** feet
8. Exit Temperature: **1,120** °F	9. Actual Volumetric Flow Rate: **2,393,587** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)

15. Emission Point Comment:

Stack temperature and flow rate are for 100 percent load, 59 degrees F, and natural gas firing. For the same operating conditions and distillate fuel oil firing,the exhaust temperature is 1,100 degrees F, and the volumetric flow rates would be 2,468,510 acfm at 11.19 percent water vapor, and 742,956 dscfm.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with pipeline quality natural gas (8,760 hours per year).**		
2. Source Classification Code (SCC): **20100202**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.790**	5. Maximum Annual Rate: **15,680**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2 grains/100 scf**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,022**
10. Segment Comment:		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with distillate fuel oil (700 hours per year maximum).**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **Thousand gallons burned**	
4. Maximum Hourly Rate: **13.889**	5. Maximum Annual Rate: **9,722**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05 by weight**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **137.6**
10. Segment Comment:		

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

Segment Description and Rate: Segment _____ of _____

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

Segment Description and Rate: Segment _____ of _____

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	**025**	**028**	**EL**
CO			**EL**
PM			**EL**
PM10			**EL**
SO2			**EL**
VOC			**EL**

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

(Optional for unregulated emissions units.)

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

1. Pollutant Emitted:	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **NOX**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10.5 ppm (gas), 42 ppm (oil)**	4. Equivalent Allowable Emissions: **69.1** lb/hour **781.2** tons/year
5. Method of Compliance: **EPA Reference Method 7E (initial), NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **CO**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **7.8 ppm (gas), 30.3 ppm (oil) max**	4. Equivalent Allowable Emissions: **69.1** lb/hour **293.9** tons/year
5. Method of Compliance: **EPA Reference Method 10 (initial), CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **PM/PM10**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **18.0 lb/hr (gas), 34.0 lb/hr (oil),**	4. Equivalent Allowable Emissions: **34.0** lb/hour **168.9** tons/year
5. Method of Compliance: **Exlusive firing of pipline quality natural gas and distillate fuel oil along with efficient combustion indicated by compliance with CO visible emission standards.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **SO2**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10.2 lb/hr (gas), 107.8 lb/hr (oil)**	4. Equivalent Allowable Emissions: **107.8** lb/hour **147.9** tons/year
5. Method of Compliance: **Exclusive firing of pipeline quality natural gas and low sulfur fuel oil.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code: **VOC**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.2 ppm (gas), 3.0 ppm (oil) max**	4. Equivalent Allowable Emissions: **8.0** lb/hour **29.8** tons/year
5. Method of Compliance: **Exclusive firing of pipeline quality natural gas and low sulfur fuel oil. Compliance with CO emission limits used as surrogate compliance for VOC**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 4 data represents 59°F emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10%** Exceptional Conditions: **20%** Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: EPA Method 9.	
5. Visible Emissions Comment: **Opacity during startup shutdown shall not exceed 10%, except of up to ten 6-minute periods in a calendar day during which the opacity shall not exceed 20%.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **To be provided** Model Number: **To be provided**	Serial Number: **To be provided**
5. Installation Date: **To be provided**	6. Performance Specification Test Date: **To be provided**
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program)** **Specific CEMS information will be provided to FDEP when available.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **O2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **To be provided** Model Number: **To be provided**	Serial Number: **To be provided**
5. Installation Date: **To be provided**	6. Performance Specification Test Date: **To be provided**
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program)** **Specific CEMS information will be provided to FDEP when available.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor _____ of _____

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

Continuous Monitoring System: Continuous Monitor _____ of _____

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig 2-4** ☐ Previously Submitted, Date _____
2.	Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Appendix A-1** ☐ Previously Submitted, Date _____
3.	Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Section 4.0** ☐ Previously Submitted, Date _____
4.	Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable **(construction application)**
5.	Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable

6.	Compliance Demonstration Reports/Records ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ _____ ☐ To be Submitted, Date (if known):__________ Test Date(s)/Pollutant(s) Tested: _____ _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute ☒ Attached, Document ID: _____ ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☒ Attached, Document ID: **Section 4.0** ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☒ Attached, Document ID: **Section 5.0** ☐ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications N/A

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

5. Acid Rain Part Application

☐ Certificate of Representation (EPA Form No. 7610-1)
  ☐ Copy Attached, Document ID:_____

☐ Acid Rain Part (Form No. 62-210.900(1)(a))
  ☐ Attached, Document ID:_____
  ☐ Previously Submitted, Date:_____

☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
  ☐ Attached, Document ID:_____
  ☐ Previously Submitted, Date:_____

☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
  ☐ Attached, Document ID:_____
  ☐ Previously Submitted, Date:_____

☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
  ☐ Attached, Document ID:_____
  ☐ Previously Submitted, Date:_____

☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
  ☐ Attached, Document ID:_____
  ☐ Previously Submitted, Date:_____

☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
  ☐ Attached, Document ID:_____
  ☐ Previously Submitted, Date:_____

☐ Not Applicable

Additional Requirements Comment

APPENDIX A-1

REGULATORY APPLICABILITY ANALYSES

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

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 60 - Standards of Performance for New Stationary Sources.				
Subpart A - General Provisions				
Notification and Recordkeeping	§60.7(b) - (h)		CT 3A-3B	General recordkeeping and reporting requirements.
Performance Tests	§60.8		CT 3A-3B	Conduct performance tests as required by EPA or FDEP. **(potential future requirement)**
Compliance with Standards	§60.11(a) thru (d), and (f)		CT 3A-3B	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		CT 3A-3B	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13(a), (b), (d), (e), and (h)		CT 3A-3B	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		CT 3A-3B	General procedures regarding reporting deadlines.
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Standards for Nitrogen Oxides	§60.332(a)(1) and (b), (f), and (i)		CT 3A-3B	Establishes NO_x limit of 75 ppmv at 15% (with corrections for heat rate and fuel bound nitrogen) for electric utility stationary gas turbines with peak heat input greater than 100 MMBtu/hr.
Standards for Sulfur Dioxide	§60.333		CT 3A-3B	Establishes exhaust gas SO_2 limit of 0.015 percent by volume (at 15% O_2, dry) and maximum fuel sulfur content of 0.8 percent by weight.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 2 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Monitoring Requirements	§60.334(a)	X	CT 3A-3B	Requires continuous monitoring of fuel consumption and ratio of water to fuel being fired in the turbine. Monitoring system must be accurate to ± 5.0 percent. Applicable to CTs using water injection for NO_x control.
Monitoring Requirements	§60.334(b)(2) and (c)		CT 3A-3B	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	§60.335		CT 3A-3B	Specifies monitoring procedures and test methods.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts B, C, Cb, Cc, Cd, Ce, D, Da, Db, Dc, E, Ea, Eb, Ec, F, G, H, I, J, K, Ka, Kb, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW		X		None of the listed NSPS' contain requirements which are applicable to the Bayside combined cycle CTs.
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants: Subparts A, B, C, D, E, F, H, I, J, K, L, M, N, O, P, Q, R, T, V, W, Y, BB, and FF		X		None of the listed NESHAPS' contain requirements which are applicable to the Bayside combined cycle CTs.
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, and XXX		X		None of the listed NESHAPS' contain requirements which are applicable to the Bayside combined cycle CTs.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 11)

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

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Application Shield	§72.32		CT 3A-3B	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.
Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	§72.40(a)(1)		CT 3A-3B	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to the Bayside combined cycle CTs.
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		CT 3A-3B	Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
Subpart H - Permit Revisions				
Fast-Track Modifications	§72.82(a) and (c)		CT 3A-3B	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CT 3A-3B	Requirement to submit an annual compliance report. **(future requirement)**

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	§75.5		CT 3A-3B	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		CT 3A-3B	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CT 3A-3B	SO_2 continuous monitoring requirements for gas- and oil-fired units. Appendix D election will be made.
Specific Provisions for Monitoring NO_x Emissions	§75.12(a) and (b)		CT 3A-3B	NO_x continuous monitoring requirements for coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units
Specific Provisions for Monitoring CO_2 Emissions	§75.13(b)		CT 3A-3B	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		CT 3A-3B	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		CT 3A-3B	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CT 3A-3B	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CT 3A-3B	General QA/QC requirements (excluding opacity).

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Reference Test Methods	§75.22		CT 3A-3B	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		CT 3A-3B	Specifies out-of-control periods and required actions to be taken when out-of-control periods occur (excluding opacity).
Subpart D - Missing Data Substitution Procedures				
General Provisions	§75.30(a)(3), (b), (c)		CT 3A-3B	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CT 3A-3B	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and (c)		CT 3A-3B	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CT 3A-3B	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CT 3A-3B	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CT 3A-3B	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CT 3A-3B	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CT 3A-3B	Requirements pertaining to general recordkeeping.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
General Recordkeeping Provisions	§75.56(b)(1)		CT 3A-3B	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CT 3A-3B	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CT 3A-3B	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.
Subpart G - Reporting Requirements				
Recertification Application	§75.63		CT 3A-3B	Requires submittal of a recertification application within 30 days after completing the recertification test. **(potential future requirement)**
Quarterly Reports	§75.64(a)(1) - (5), (b), (c), and (d)		CT 3A-3B	Quarterly data report requirements.
40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program		X		The Acid Rain Nitrogen Oxides Emission Reduction Program only applies to coal-fired utility units that are subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 77 - Excess Emissions				
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		CT 3A-3B	Requirement to submit offset plans for excess SO_2 emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO_2 emissions. Required contents of offset plans are specified **(potential future requirement)**.
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		CT 3A-3B	Requirement for the Designated Representative to hold enough allowances in the appropriate compliance subaccount to cover deductions to be made by EPA if a timely and complete offset plan is not submitted or if EPA disapproves a proposed offset plan **(potential future requirement)**.
Penalties for Excess Emissions of Sulfur Dioxide	§77.6		CT 3A-3B	Requirement to pay a penalty if excess emissions of SO_2 occur at any affected unit during any year **(potential future requirement)**.
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		The Bayside combined cycle CTs will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		Bayside personnel will not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing will be conducted by persons who comply with Subpart B requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 9 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		Bayside will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		The Bayside combined cycle CTs will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	§82.154	X		Bayside personnel will not maintain, service, repair, or dispose of any applianc-es. All such activities will be performed by independent parties in compliance with §82.154 prohibitions.
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors will maintain, service, repair, and dispose of any appliances in com-pliance with §82.156 required practices.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 10 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart F - Recycling and Emissions Reduction				
Required Practices	§82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by §82.152- any device which contains and uses a Class I or II substance as a refrigerant and which is used for household or commercial purposes, including any air conditioner, refrigerator, chiller, or freezer	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		Bayside personnel will not maintain, service, repair, or dispose of any appliances and therefore are not subject to technician certification requirements.
Certification By Owners of Recovery and Recycling Equipment	§82.162	X		Bayside personnel will not maintain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.
Reporting and Recordkeeping Requirements	§82.166(k), (m), and (n)		Appliances as defined by §82.152	Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep servicing records documenting the date and type of service, as well as the quantity of refrigerant added.

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

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 64 - Regulations on Compliance Assurance Monitoring for Major Stationary Sources		X		Exempt per §64.2(b)(1)(iii) since CTs 1A-2D will meet Acid Rain Program monitoring requirements.
40 CFR Part 68 - Provisions for Chemical Accident Prevention			Ammonia Storage	Subject to provisions of 40 CFR Part 68 due to anhydrous ammonia storage.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 49, 53, 54, 55, 56, 57, 58, 59, 62, 66, 67, 69, 71, 74, 76, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 600, and 610		X		The listed regulations do not contain any requirements which are applicable to the Bayside combined cycle CTs.

Source: ECT, 2001.

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-4, F.A.C. - Permits: Part I General					
Scope of Part I	62-4.001, F.A.C.	X			Contains no applicable requirements.
Definitions	62-4.020, .021, F.A.C.	X			Contains no applicable requirements.
Transferability of Definitions	62-4.021, .021, F.A.C.	X			Contains no applicable requirements.
General Prohibition	62-4.030, F.A.C		X		All stationary air pollution sources must be permitted, unless otherwise exempted.
Exemptions	62-4.040, F.A.C		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits	62-4.050, F.A.C.		X		General permitting requirements.
Surveillance Fees	62-4.052, F.A.C.	X			Not applicable to air emission sources.
Permit Processing	62-4.055, F.A.C.	X			Contains no applicable requirements.
Consultation	62-4.060, F.A.C.	X			Consultation is encouraged, not required.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C	X			Establishes standard procedures for FDEP. Requirement is not applicable to the Bayside combined cycle CTs.
Modification of Permit Conditions	62-4.080, F.A.C	X			Application is for initial contruction permit. Modification of permit conditions is not being requested.
Renewals	62-4.090, F.A.C.		X		Establishes permit renewal criteria. Additional criteria are cited at 62-213.430(3), F.A.C. **(future requirement)**
Suspension and Revocation	62-4.100, F.A.C.		X		Establishes permit suspension and revocation criteria.

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

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

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 3 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-204, F.A.C. - State Implementation Plan					
State Implementation Plan	62-204.100, .200, .220(1)-(3), .240, .260, .320, .340, .360, .400, and .500, F.A.C.	X			Contains no applicable requirements.
Ambient Air Quality Protection	62-204.220(4), F.A.C.		X		Assessments of ambient air pollutant impacts must be made using applicable air quality models, data bases, and other requirements approved by FDEP and specified in 40 CFR Part 51, Appendix W.
State Implementation Plan	62-204.800(1) - (6), F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800(7)(a), (b)16.,(b)39., (c), (d), and (e), F.A.C.			CT 3A-3B	NSPS Subpart GG; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(8) - (13), (15), (17), (20), and (22) F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800 (14), (16), (18), (19), F.A.C.			CT 3A-3B	Acid Rain Program; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(21), F.A.C.		X		Protection of Stratospheric Ozone; see Table A-1 for detailed federal regulatory citations.
Chapter 62-210, F.A.C. - Stationary Sources - General Requirements					
Purpose and Scope	62-210.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-210.200, F.A.C.	X			Contains no applicable requirements.
Small Business Assistance Program	62-210.220, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 4 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permits Required	62-210.300(1) and (3), F.A.C.		X		Air construction permit required. Exemptions from permitting specified for certain facilities and sources.
Permits Required	62-210.300(2), F.A.C.		X		Air operation permit required. **(future requirement)**
Air General Permits	62-210.300(4), F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Notification of Startup	62-210.300(5), F.A.C.	X			Sources which have been shut down for more than one year shall notify the FDEP prior to startup.
Emission Unit Reclassification	62-210.300(6), F.A.C.		X		Emission unit reclassification **(potential future requirement)**
Public Notice and Comment Public Notice of Proposed Agency Action	62-210.350(1), F.A.C.		X		All permit applicants required to publish notice of proposed agency action.
Additional Notice Requirements for Sources Subject to Prevention of Significant Deterioration or Nonattainment Area New Source Review	62-210.350(2), F.A.C.		X		Additional public notice requirements for PSD and nonattainment area NSR applications.
Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources	62-210.350(3), F.A.C.		X		Notice requirements for Title V operating permit applicants **(future requirement)**.
Public Notice Requirements for FESOPS and 112(g) Emission Sources	62-210.350(4) and (5), F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Administrative Permit Corrections	62-210.360, F.A.C.	X			An administrative permit correction is not requested in this application.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 5 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reports					
Notification of Intent to Relocate Air Pollutant Emitting Facility	62-210.370(1), F.A.C.	X			Project does not have any relocatable emission units.
Annual Operating Report for Air Pollutant Emitting Facility	62-210.370(3), F.A.C.		X		Specifies annual reporting requirements. **(future requirement)**.
Stack Height Policy	62-210.550, F.A.C.		X		Limits credit in air dispersion studies to good engineering practice (GEP) stack heights for stacks constructed or modified since 12/31/70.
Circumvention	62-210.650, F.A.C.		X		An applicable air pollution control device cannot be circumvented and must be operated whenever the emission unit is operating.
Excess Emissions	62-210.700(1), F.A.C.		X		Excess emissions due to startup, shut down, and malfunction are permitted for no more than two hours in any 24 hour period unless specifically authorized by the FDEP for a longer duration. **Excess emissions for up to 18 hours in a 24 hour period are specifically requested for the Bayside combined cycle CTs. See Section 2.2 of the PSD permit application for details.**
Excess Emissions	62-210.700(2) and (3), F.A.C.	X			Not applicable to the Bayside combined cycle CTs.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 6 of 12)

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

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 7 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.	X			Contains no applicable requirements.
Annual Emissions Fee	62-213.205(1), (4), and (5), F.A.C.		X		Annual emissions fee and documentation requirements. **(future requirement)**
Annual Emissions Fee	62-213.205(2) and (3), F.A.C.	X			Contains no applicable requirements.
Title V Air General Permits	62-213.300, F.A.C.	X			No eligible facilities
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required. **(future requirement)**
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met **(potential future requirement)**.
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be implemented pending permit revision if specific criteria are met **(potential future requirement)**.
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			CT 3A-3B	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 8 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Applications	62-213.420(1)(a)2. and (1)(b), (2), (3), and (4), F.A.C.		X		Title V operating permit application required no later than 180 days after commencing operation. **(future requirement)**
Permit Issuance, Renewal, and Revision					
Action on Application	62-213.430(1), F.A.C.	X			Contains no applicable requirements.
Permit Denial	62-213.430(2), F.A.C.	X			Contains no applicable requirements.
Permit Renewal	62-213.430(3), F.A.C.		X		Permit renewal application requirements **(future requirement)**.
Permit Revision	62-213.430(4), F.A.C.		X		Permit revision application requirements **(potential future requirement)**.
EPA Recommended Actions	62-213.430(5), F.A.C.	X			Contains no applicable requirements.
Insignificant Emission Units	62-213.430(6), F.A.C.	X			Contains no applicable requirements.
Permit Content	62-213.440, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and conditions. **(future requirement)**
Forms and Instructions	62-213.900, F.A.C.		X		Contains annual emissions fee form requirements.
Chapter 62-214—Requirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	§62-214.100, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 9 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Applicability	§62-214.300, F.A.C.		X		Project includes Acid Rain affected units, therefore compliance with §62-213 and §62-214, F.A.C., is required.
Applications	§62-214.320, F.A.C.			CT 3A-3B	Acid Rain application requirements. Application for new units are due at least 24 months before the later of 1/1/2000 or the date on which the unit commences operation. **(future requirement)**
Acid Rain Compliance Plan and Compliance Options	§62-214.330(1)(a), F.A.C.			CT 3A-3B	Acid Rain compliance plan requirements. Sulfur dioxide requirements become effective the later of 1/1/2000 or the deadline for CEMS certification pursuant to 40 CFR Part 75. **(future requirement)**
Exemptions	§62-214.340, F.A.C.		X		An application may be submitted for certain exemptions **(potential future requirement)**.
Certification	§62-214.350, F.A.C.			CT 3A-3B	The designated representative must certify all Acid Rain submissions. **(future requirement)**
Department Action on Applications	§62-214.360, F.A.C.	X			Contains no applicable requirements.
Revisions and Administrative Corrections	§62-214.370, F.A.C.			CT 3A-3B	Defines revision procedures and automatic amendments **(potential future requirement)**..
Acid Rain Part Content	§62-214.420, F.A.C.	X			Agency procedures, contains no applicable requirements.
Implementation and Termination of Compliance Options	§62-214.430, F.A.C.			CT 3A-3B	Defines permit activation and termination procedures **(potential future requirement)**.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 10 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Chapter 62-256 - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-256.200, F.A.C.	X			Contains no applicable requirements.
Prohibitions	**62-256.300, F.A.C.**[1]		X		Prohibits open burning.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.
Land Clearing	**62-256.500, F.A.C.**[1]		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	**62-256.600, F.A.C.**[1]		X		Prohibits industrial open burning
Open Burning allowed	62-256.700, F.A.C.		X		Specifies allowable open burning activities. **(potential future requirement)**
Effective Date	62-256.800, F.A.C.	X			Contains no applicable requirements.
Chapter 62-257 - Asbestos Fee	62-257, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 11 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-296 - Stationary Source - Emission Standards					
Purpose and Scope	62-296.100, F.A.C.	X			Contains no applicable requirements
General Pollutant Emission Limiting Standard, Volatile Organic Compounds Emissions	62-296.320(1), F.A.C.		X		Known and existing vapor control devices must be applied as required by the Department.
General Pollutant Emission Limiting Standard, Objectionable Odor Prohibited	62-296.320(2), F.A.C.		X		Objectionable odor release is prohibited.
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	**62-296.320(3), F.A.C.**[1]		X		Open burning in connection with industrial, commercial, or municipal operations is prohibited.
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.	X			Project does not have any applicable emission units. Combustion emission units are exempt per 62-296.320(4)(a)1a.
General Particulate Emission Limiting Standard, General Visible Emission Standard	62-296.320(4)(b), F.A.C.		X		Opacity limited to 20 percent, unless otherwise permitted. Test methods specified.
General Particulate Emission Limiting Standard, Unconfined Emission of Particulate Matter	62-296.320(4)(c), F.A.C.		X		Reasonable precautions must be taken to prevent unconfined particulate matter emission.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.417, F.A.C.	X			None of the referenced standards are applicable to the Bayside combined cycle CTs.
Reasonably Available Control Technology (RACT) Volatile Organic Compounds (VOC) and Nitrogen Oxides (NO_x) Emitting Facilities	62-296.500 through 62-296.516, F.A.C.	X			Project is not located in an ozone nonattainment area or an ozone air quality maintenance area.

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO_x-Emitting Facilities	62-296.570, F.A.C.	X			Project is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (i.e., is not located in Broward, Dade or Palm Beach Counties)
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			Project is not located in a lead non-attainment area or a lead air quality maintenance area.
Reasonably Available Control Technology (RACT)—Particulate Matter	§62-296.700 through 62-296.712, F.A.C.	X			Project is located in a PM air quality maintenance area. However, there are no limits applicable to CTs.
Chapter 62-297 - Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.
General Compliance Test Requirements	62-297.310, F.A.C.		X		Specifies general compliance test requirements.
Compliance Test Methods	62-297.401, F.A.C.	X			Contains no applicable requirements.
Supplementary Test Procedures	62-297.440, F.A.C.	X			Contains no applicable requirements.
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Not applicable to the Bayside combined cycle CTs.
CEMS Performance Specifications	62-297.520, F.A.C.	X			Contains no applicable requirements.
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.	X			Exceptions or alternate procedures have not been requested.

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

Source: ECT, 2001.

APPENDIX A-2

FUEL ANALYSES OR SPECIFICATIONS

Typical Natural Gas Composition

Component	Mole Percent (by volume)
<u>Gas Composition</u>	
Hexane+	0.018
Propane	0.190
I-butane	0.010
N-butane	0.007
Pentane	0.002
Nitrogen	0.527
Methane	96.195
CO_2	0.673
Ethane	2.379
<u>Other Characteristics</u>	
Heat content	1,022 Btu/ft^3 with 14.73 psia, dry
Real specific gravity	0.5776
Sulfur content (maximum)	2.0 gr/100 scf

Note: Btu/ft^3 = British thermal units per cubic foot.
psia = pounds per square inch absolute.
gr/100 scf = grains per 100 standard cubic foot.

Source: TEC, 1999.

Typical No. 2 Fuel Oil Analysis

Parameter	Value
Specific gravity @ 60EF (maximum)	0.876
Viscosity, saybolt (SUS) @ 100EF	
Minimum	40.2
Maximum	32.6
Flash point, EF (minimum)	100
Pour point, EF (minimum)	0
Minimum gross heating value, Btu/gal	
LHV	129,811
HHV	137,600
Water and sediment, percent by volume (maximum)	0.05
Ash, percent by weight (maximum)	0.01
Sulfur, percent by weight (maximum)	0.05
Fuel-bound nitrogen, percent by weight (maximum)	0.015
Trace constituents, ppm (maximum)	
Lead	1.0
Sodium	1.0
Vanadium	0.5

Note: SUS = Saybolt Universal Seconds.
Btu/gal = British thermal units per gallon.
LHV = lower heating value.
HHV = higher heating value.

Source: TEC, 1992.

APPENDIX B

EMISSION RATE CALCULATIONS

Table B-1. TEC Bayside Power Station, SC Units 3A and 3B CT Operating Scenarios - General Electric 7241FA CT

Case	Ambient Temperature (oF)	Load (%)	Simple Cycle Unit 3A, 3B	Annual Profile (hr/yr)	Evaporative Cooling	Natural Gas Firing	Fuel Oil Firing
1	20	100	X			X	X
2	20	75	X			X	X
3	20	50	X			X	X
4	59	100	X	8,060 (gas), 700 (oil)		X	X
5	59	75	X			X	X
6	59	50	X			X	X
7	90	100	X		X	X	X
8	90	75	X			X	X
9	90	50	X			X	X

Sources: TEC, 2003.
ECT, 2003.

Table B-2. TEC Bayside Power Station, SC Units 3A and 3B
CT Hourly Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1]		SO_2[2]		H_2SO_4[3]		Lead[4]	
			(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
20	1	100	18.0	2.27	10.2	1.28	1.2	0.15	0.0306	0.00386
	2	75	18.0	2.27	8.2	1.03	0.9	0.12	0.0245	0.00309
	3	50	18.0	2.27	6.5	0.82	0.7	0.09	0.0196	0.00247
59	4	100	18.0	2.27	9.5	1.20	1.1	0.14	0.0286	0.00361
	5	75	18.0	2.27	7.7	0.97	0.9	0.11	0.0232	0.00292
	6	50	18.0	2.27	6.2	0.78	0.7	0.09	0.0186	0.00235
90	7	100	18.0	2.27	8.8	1.10	1.0	0.13	0.0264	0.00332
	8	75	18.0	2.27	7.2	0.91	0.8	0.10	0.0216	0.00272
	9	50	18.0	2.27	5.8	0.73	0.7	0.08	0.0174	0.00220
		Maximums	**18.0**	**2.27**	**10.2**	**1.28**	**1.2**	**0.15**	**0.0306**	**0.0039**

Temp. (°F)	Case	Load (%)	NO_x			CO			VOC[6]		
			(ppmvd)[5]	(lb/hr)	(g/sec)	(ppmvd)[5]	(lb/hr)	(g/sec)	(ppmvd)[5]	(lb/hr)	(g/sec)
20	1	100	10.5	73.8	9.30	7.2	30.5	3.84	1.2	3.0	0.38
	2	75	10.5	58.6	7.38	7.1	30.0	3.79	1.1	2.6	0.33
	3	50	10.5	45.7	5.76	7.4	31.3	3.95	1.2	2.8	0.35
59	4	100	10.5	69.1	8.71	7.2	30.5	3.84	1.2	3.0	0.38
	5	75	10.5	55.1	6.94	7.2	30.5	3.84	1.1	2.6	0.33
	6	50	10.5	43.3	5.46	7.6	32.2	4.05	1.2	2.8	0.35
90	7	100	10.5	63.3	7.97	7.1	30.0	3.79	1.2	3.0	0.38
	8	75	10.5	51.5	6.49	7.3	30.9	3.89	1.2	2.8	0.35
	9	50	10.5	41.0	5.17	7.8	33.0	4.16	1.2	2.8	0.35
		Maximums	**10.5**	**73.8**	**9.30**	**7.8**	**33.0**	**4.16**	**1.2**	**3.0**	**0.38**

[1] As measured by EPA Reference Methods 201 and 202.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft^3.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] AP-42, EPA, May 1998 - Draft.
[5] Corrected to 15% O_2.
[6] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2003.
GE, 1998.

Table B-3. TEC Bayside Power Station, SC Units 3A and 3B
CT Hourly Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

Temp. (°F)	Case	Load (%)	PM/PM_{10} [1] (lb/hr)	PM/PM_{10} [1] (g/sec)	SO_2 [2] (lb/hr)	SO_2 [2] (g/sec)	H_2SO_4 [3] (lb/hr)	H_2SO_4 [3] (g/sec)	Lead [4] (lb/hr)	Lead [4] (g/sec)
20	1	100	34.0	4.28	107.8	13.58	12.4	1.56	0.104	0.0131
	2	75	34.0	4.28	87.4	11.02	10.0	1.27	0.084	0.0106
	3	50	34.0	4.28	68.2	8.59	7.8	0.99	0.067	0.0084
59	4	100	34.0	4.28	101.5	12.79	11.7	1.47	0.098	0.0123
	5	75	34.0	4.28	82.5	10.40	9.5	1.19	0.079	0.0100
	6	50	34.0	4.28	64.9	8.18	7.5	0.94	0.063	0.0079
90	7	100	34.0	4.28	92.3	11.63	10.6	1.34	0.093	0.0117
	8	75	34.0	4.28	75.6	9.53	8.7	1.09	0.073	0.0092
	9	50	34.0	4.28	59.8	7.54	6.9	0.87	0.058	0.0073
		Maximums	**34.0**	**4.28**	**107.8**	**13.58**	**12.4**	**1.56**	**0.104**	**0.0131**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd) [5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd) [5]	CO (lb/hr)	CO (g/sec)	VOC [6] (ppmvd) [5]	VOC [6] (lb/hr)	VOC [6] (g/sec)
20	1	100	42.0	339.4	42.76	14.2	69.7	8.79	2.8	7.7	0.97
	2	75	42.0	273.1	34.41	16.5	87.5	11.02	2.7	8.0	1.00
	3	50	42.0	210.8	26.57	24.0	116.4	14.66	2.8	7.7	0.97
59	4	100	42.0	320.3	40.35	14.0	69.1	8.70	2.8	7.7	0.97
	5	75	42.0	258.0	32.51	16.0	82.9	10.44	2.7	7.8	0.99
	6	50	42.0	200.8	25.30	24.5	114.9	14.47	2.9	7.7	0.97
90	7	100	42.0	291.2	36.69	13.9	68.6	8.64	2.8	7.5	0.95
	8	75	42.0	235.9	29.73	16.4	82.0	10.33	2.8	7.7	0.97
	9	50	42.0	184.7	23.28	30.3	136.4	17.19	3.0	7.5	0.95
		Maximums	**42.0**	**339.4**	**42.76**	**30.3**	**136.4**	**17.19**	**3.0**	**8.0**	**1.00**

[1] As measured by EPA Reference Methods 201 and 202.
[2] Based on fuel oil sulfur content of 0.05 wt percent.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] Based on 1.0 ppmw lead content of fuel oil, S&L, 2000.
[5] Corrected to 15% O_2.
[6] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2003.
GE, 1998.

Table B-4a. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing: Noncriteria Pollutants; 20 °F

Maximum Hourly Heat Input: (Case 1)	1,960	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,834	10^6 Btu/hr
Maximum Annual Hours:	8,060	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	4.30E-08	8.43E-05	1.06E-05	3.18E-04
Acetaldehyde	4.00E-06	7.84E-03	9.88E-04	2.96E-02
Acrolein	6.40E-07	1.25E-03	1.58E-04	4.73E-03
Benzene	1.20E-06	2.35E-03	2.96E-04	8.87E-03
Ethylbenzene	3.20E-06	6.27E-03	7.90E-04	2.37E-02
Formaldehyde	6.49E-05	1.27E-01	1.60E-02	4.80E-01
Naphthalene	1.30E-07	2.55E-04	3.21E-05	9.61E-04
Polycyclic Organic Matter	2.20E-07	4.31E-04	5.43E-05	1.63E-03
Propylene Oxide	2.90E-06	5.68E-03	7.16E-04	2.14E-02
Toluene	1.30E-05	2.55E-02	3.21E-03	9.61E-02
Xylene	6.40E-06	1.25E-02	1.58E-03	4.73E-02

[1] The HAP emission factors for lean premix (LPM) combustion are based on the AP-42 (Section 3.1, April, 2000) diffusion flame emission factors and 90% reduction for LPM combustion.

Source: ECT, 2003.

Table B-4b. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing: Noncriteria Pollutants; 59 °F

Maximum Hourly Heat Input: (Case 4)	1,834	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,834	10^6 Btu/hr
Maximum Annual Hours:	8,060	hrs/yr

Pollutant	Emission Factor[1] ($lb/10^6$ Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	4.30E-08	7.89E-05	9.94E-06	3.18E-04
Acetaldehyde	4.00E-06	7.34E-03	9.24E-04	2.96E-02
Acrolein	6.40E-07	1.17E-03	1.48E-04	4.73E-03
Benzene	1.20E-06	2.20E-03	2.77E-04	8.87E-03
Ethylbenzene	3.20E-06	5.87E-03	7.39E-04	2.37E-02
Formaldehyde	6.49E-05	1.19E-01	1.50E-02	4.80E-01
Naphthalene	1.30E-07	2.38E-04	3.00E-05	9.61E-04
Polycyclic Organic Matter	2.20E-07	4.03E-04	5.08E-05	1.63E-03
Propylene Oxide	2.90E-06	5.32E-03	6.70E-04	2.14E-02
Toluene	1.30E-05	2.38E-02	3.00E-03	9.61E-02
Xylene	6.40E-06	1.17E-02	1.48E-03	4.73E-02

[1] The HAP emission factors for lean premix (LPM) combustion are based on the AP-42 (Section 3.1, April, 2000) diffusion flame emission factors and 90% reduction for LPM combustion.

Source: ECT, 2003.

Table B-4c. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing: Noncriteria Pollutants; 90 °F

Maximum Hourly Heat Input: (Case 4)	1,688	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,834	10^6 Btu/hr
Maximum Annual Hours:	8,060	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	4.30E-08	7.26E-05	9.15E-06	3.18E-04
Acetaldehyde	4.00E-06	6.75E-03	8.51E-04	2.96E-02
Acrolein	6.40E-07	1.08E-03	1.36E-04	4.73E-03
Benzene	1.20E-06	2.03E-03	2.55E-04	8.87E-03
Ethylbenzene	3.20E-06	5.40E-03	6.81E-04	2.37E-02
Formaldehyde	6.49E-05	1.10E-01	1.38E-02	4.80E-01
Naphthalene	1.30E-07	2.19E-04	2.77E-05	9.61E-04
Polycyclic Organic Matter	2.20E-07	3.71E-04	4.68E-05	1.63E-03
Propylene Oxide	2.90E-06	4.90E-03	6.17E-04	2.14E-02
Toluene	1.30E-05	2.19E-02	2.77E-03	9.61E-02
Xylene	6.40E-06	1.08E-02	1.36E-03	4.73E-02

[1] The HAP emission factors for lean premix (LPM) combustion are based on the AP-42 (Section 3.1, April, 2000) diffusion flame emission factors and 90% reduction for LPM combustion.

Source: ECT, 2003.

Table B-5a. TEC Bayside Power Station, SC Units 3A and 3B CT Emission Rates - General Electric 7241FA CT (Per CT) Distillate Fuel Oil-Firing: Noncriteria Pollutants; 20 °F

Maximum Hourly Heat Input: (Case 1)	2,139	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	2,015	10^6 Btu/hr
Maximum Annual Hours:	700	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	1.60E-05	3.42E-02	4.31E-03	1.13E-02
Arsenic	1.10E-05	2.35E-02	2.96E-03	7.76E-03
Benzene	5.50E-05	1.18E-01	1.48E-02	3.88E-02
Beryllium	3.10E-07	6.63E-04	8.35E-05	2.19E-04
Cadmium	4.80E-06	1.03E-02	1.29E-03	3.39E-03
Chromium	1.10E-05	2.35E-02	2.96E-03	7.76E-03
Formaldehyde	2.80E-04	5.99E-01	7.54E-02	1.97E-01
Lead	1.40E-05	2.99E-02	3.77E-03	9.87E-03
Manganese	7.90E-04	1.69E+00	2.13E-01	5.57E-01
Mercury	1.20E-06	2.57E-03	3.23E-04	8.46E-04
Naphthalene	3.50E-05	7.49E-02	9.43E-03	2.47E-02
Nickel	4.60E-06	9.84E-03	1.24E-03	3.24E-03
PAH	4.00E-05	8.55E-02	1.08E-02	2.82E-02
Selenium	2.50E-05	5.35E-02	6.74E-03	1.76E-02

[1] EPA AP-42 HAP Emission Factors, Section 3.1, April, 2000.

ECT, 2003.

Table B-5b. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing: Noncriteria Pollutants; 59 °F

100% Load Hourly Heat Input: (Case 4)	2,015	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	2,015	10^6 Btu/hr
Maximum Annual Hours:	700	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	Emission Rates		
		(lb/hr)	(g/s)	(ton/yr)
1,3-Butadiene	1.60E-05	3.22E-02	4.06E-03	1.13E-02
Arsenic	1.10E-05	2.22E-02	2.79E-03	7.76E-03
Benzene	5.50E-05	1.11E-01	1.40E-02	3.88E-02
Beryllium	3.10E-07	6.25E-04	7.87E-05	2.19E-04
Cadmium	4.80E-06	9.67E-03	1.22E-03	3.39E-03
Chromium	1.10E-05	2.22E-02	2.79E-03	7.76E-03
Formaldehyde	2.80E-04	5.64E-01	7.11E-02	1.97E-01
Lead	1.40E-05	2.82E-02	3.55E-03	9.87E-03
Manganese	7.90E-04	1.59E+00	2.01E-01	5.57E-01
Mercury	1.20E-06	2.42E-03	3.05E-04	8.46E-04
Naphthalene	3.50E-05	7.05E-02	8.89E-03	2.47E-02
Nickel	4.60E-06	9.27E-03	1.17E-03	3.24E-03
PAH	4.00E-05	8.06E-02	1.02E-02	2.82E-02
Selenium	2.50E-05	5.04E-02	6.35E-03	1.76E-02

[1] EPA AP-42 HAP Emission Factors, Section 3.1, April, 2000.

ECT, 2003.

Table B-5c. TEC Bayside Power Station, SC Units 3A and 3B
CT Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing: Noncriteria Pollutants; 90 °F

100% Load Hourly Heat Input: (Case 7)	1,832	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	2,015	10^6 Btu/hr
Maximum Annual Hours:	700	hrs/yr

Pollutant	Emission Factor[1] ($lb/10^6$ Btu)	Emission Rates (lb/hr)	Emission Rates (g/s)	Emission Rates (ton/yr)
1,3-Butadiene	1.60E-05	2.93E-02	3.69E-03	1.13E-02
Arsenic	1.10E-05	2.02E-02	2.54E-03	7.76E-03
Benzene	5.50E-05	1.01E-01	1.27E-02	3.88E-02
Beryllium	3.10E-07	5.68E-04	7.16E-05	2.19E-04
Cadmium	4.80E-06	8.80E-03	1.11E-03	3.39E-03
Chromium	1.10E-05	2.02E-02	2.54E-03	7.76E-03
Formaldehyde	2.80E-04	5.13E-01	6.46E-02	1.97E-01
Lead	1.40E-05	2.57E-02	3.23E-03	9.87E-03
Manganese	7.90E-04	1.45E+00	1.82E-01	5.57E-01
Mercury	1.20E-06	2.20E-03	2.77E-04	8.46E-04
Naphthalene	3.50E-05	6.41E-02	8.08E-03	2.47E-02
Nickel	4.60E-06	8.43E-03	1.06E-03	3.24E-03
PAH	4.00E-05	7.33E-02	9.24E-03	2.82E-02
Selenium	2.50E-05	4.58E-02	5.77E-03	1.76E-02

[1] EPA AP-42 HAP Emission Factors, Section 3.1, April, 2000.

ECT, 2003.

Table B-6. TEC Bayside Power Station, SC Units 3A and 3B
CT Annual Emission Rates

Source	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT-3A	4 - NG	8,060	69.1	278.5	30.5	122.8	3.0	12.2
CT-3B	4 - NG	8,060	69.1	278.5	30.5	122.8	3.0	12.2
CT-3A	4 - Oil	700	320.3	112.1	69.1	24.2	7.7	2.7
CT-3B	4 - Oil	700	320.3	112.1	69.1	24.2	7.7	2.7
		Totals	**N/A**	**781.2**	**N/A**	**293.9**	**N/A**	**29.8**

Source	Case	Annual Operations (hrs/yr)	Emission Rates							
			PM/PM_{10}		SO_2		H_2SO_4		Lead	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT-3A	4 - NG	8,060	18.0	72.5	9.5	38.4	1.09	4.4	0.029	0.115
CT-3B	4 - NG	8,060	18.0	72.5	9.5	38.4	1.09	4.4	0.029	0.115
CT-3A	4 - Oil	700	34.0	11.9	101.5	35.5	11.66	4.1	0.098	0.034
CT-3B	4 - Oil	700	34.0	11.9	101.5	35.5	11.66	4.1	0.098	0.034
		Totals	**N/A**	**168.9**	**N/A**	**147.9**	**N/A**	**17.0**	**N/A**	**0.299**

1. CT-3A and CT-3B operating with natural gas-firing at a 92% capacity factor; 8,060 hours/year at base load (Case 4).
2. CT-3A and CT-3B operating with fuel oil-firing at a 8% capacity factor; 700 hours/year at base load (Case 4).
3. SO_2 and H_2SO_4 rates based on natural gas sulfur content of 2.0 gr/100 ft^3 and 7.5% conversion of SO_2 to H_2SO_4.
4. SO_2 and H_2SO_4 rates based on fuel oil sulfur content of 0.05 wt. percent and 7.5% conversion of SO_2 to H_2SO_4.

Sources: GE, 1998.
ECT, 2003.
TEC, 2003.

Table B-7. TEC Bayside Power Station, SC Units 3A and 3B
General Electric 7241FA CT
NSPS GG NO_x Limits

Fuel	7241FA Gas Turbine ISO Heat Rate		F	NO_x Std
	(Btu/kw-hr)	(kj/w-hr)		(ppmvd)
Gas	9,370	9.886	0.0	109.2
Distillate	10,040	10.593	0.0	102.0

Sources: ECT, 2003.

Table B-8a. TEC Bayside Power Station, SC Unit 3A and 3B
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

A. Exhaust MW

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %								
		100 % Load			75 % Load			50 % Load		
		20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.90	0.89	0.87	0.91	0.88	0.87	0.90	0.89	0.86
N_2	28.016	75.06	74.38	72.32	75.07	74.43	72.37	75.18	74.54	72.50
O_2	32.000	12.56	12.38	11.96	12.59	12.52	12.10	12.90	12.85	12.48
CO_2	44.010	3.87	3.87	3.80	3.85	3.80	3.73	3.71	3.65	3.56
H_2O	17.008	7.61	8.49	11.06	7.59	8.37	10.93	7.31	8.07	10.60
SO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	100.00	100.01	100.01	100.01	100.00	100.00	100.00	100.00	100.00
Exhaust MW (lb/mole)		28.41	28.30	27.99	28.41	28.31	28.00	28.43	28.33	28.02
Exhaust Flow (lb/sec)		1,053.08	981.13	910.01	839.46	801.53	751.61	689.69	664.87	630.85
Exhaust Temp. (°F)		1,081	1,117	1,141	1,111	1,139	1,166	1,160	1,184	1,200
(K)		856	876	889	873	888	903	900	913	922
Exhaust O_2 (Vol %, Dry)		13.59	13.53	13.45	13.62	13.66	13.58	13.92	13.98	13.96

Sources: ECT, 2003.
GE, 1998.

Table B-8b. TEC Bayside Power Station, SC Unit 3A and 3B
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	2,501,394	2,393,587	2,279,099	2,032,504	1,982,448	1,911,361	1,720,962	1,689,336	1,636,463
Velocity (fps)	151.0	144.5	137.6	122.7	119.7	115.4	103.9	102.0	98.8
Velocity (m/s)	46.0	44.0	41.9	37.4	36.5	35.2	31.7	31.1	30.1
SCFM, Dry[1]	791,825	733,365	668,502	631,260	599,825	552,825	519,904	498,776	465,339
ACFM (15% O_2, Dry)	2,861,380	2,736,637	2,560,494	2,316,258	2,227,959	2,110,800	1,887,869	1,822,012	1,720,949

Sources: ECT, 2003.
GE, 1998.

Table B-8c. TEC Bayside Power Station, SC Unit 3A and 3B CT Exhaust Data - General Electric 7241FA CT Natural Gas-Firing

C. Correction of GE CO and VOC Concentrations to 15% O_2, dry

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	8.9	9.0	9.0	8.8	8.8	9.1	8.8	8.9	9.2
CO (15% O_2)	7.2	7.2	7.1	7.1	7.2	7.3	7.4	7.6	7.8
VOC (ppmvw)	1.4	1.4	1.4	1.2	1.2	1.3	1.3	1.3	1.3
VOC (ppmvd)	1.5	1.5	1.6	1.3	1.3	1.5	1.4	1.4	1.5
VOC (15% O_2)	1.2	1.2	1.2	1.1	1.1	1.2	1.2	1.2	1.2

Sources: ECT, 2003.
GE, 1998.

Table B-9a. TEC Bayside Power Station, SC Unit 3A and 3B
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

A. Exhaust MW

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %								
		100 % Load			75 % Load			50 % Load		
		20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.87	0.85	0.85	0.85	0.86	0.85	0.87	0.87	0.85
N_2	28.016	71.82	71.31	70.02	71.53	71.26	70.24	72.47	72.21	71.08
O_2	32.000	11.17	11.04	10.85	10.49	10.63	10.77	11.37	11.59	11.69
CO_2	44.010	5.61	5.61	5.50	6.02	5.88	5.59	5.60	5.40	5.12
H_2O	17.008	10.54	11.19	12.79	11.11	11.37	12.56	9.70	9.94	11.27
SO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	100.01	100.00	100.01	100.00	100.00	100.01	100.01	100.01	100.01
Exhaust MW (lb/mole)		28.30	28.22	28.02	28.28	28.23	28.06	28.40	28.35	28.16
Exhaust Flow (lb/sec)		1,085.99	1,021.29	941.25	811.85	784.24	751.05	677.70	667.94	645.91
Exhaust Temp. (°F)		1,067	1,098	1,130	1,184	1,195	1,200	1,200	1,200	1,200
(K)		848	865	883	913	919	922	922	922	922
Exhaust O_2 (Vol %, Dry)		12.49	12.43	12.44	11.80	11.99	12.32	12.59	12.87	13.17

Sources: ECT, 2003.
GE, 1998.

Table B-9b. TEC Bayside Power Station, SC Unit 3A and 3B
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	2,565,225	2,468,510	2,338,219	2,066,743	2,012,963	1,945,329	1,734,167	1,712,182	1,666,850
Velocity (fps)	154.8	149.0	141.1	124.8	121.5	117.4	104.7	103.3	100.6
Velocity (m/s)	47.2	45.4	43.0	38.0	37.0	35.8	31.9	31.5	30.7
SCFM, Dry[1]	793,504	742,956	677,155	590,027	569,184	541,040	498,086	490,465	470,428
ACFM (15% O_2, Dry)	3,272,679	3,146,844	2,923,523	2,833,193	2,693,164	2,474,511	2,205,243	2,098,885	1,936,533

Sources: ECT, 2003.
GE, 1998.

Table B-9c. TEC Bayside Power Station, SC Unit 3A and 3B CT Exhaust Data - General Electric 7241FA CT Distillate Fuel Oil-Firing

C. Correction of GE CO and VOC Concentrations to 15% O_2, dry

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	20.3	20.1	19.9	25.4	24.2	23.9	33.8	33.3	39.7
CO (15% O_2)	14.2	14.0	13.9	16.5	16.0	16.4	24.0	24.5	30.3
VOC (ppmvw)	3.6	3.6	3.5	3.7	3.6	3.6	3.6	3.6	3.5
VOC (ppmvd)	4.0	4.1	4.0	4.2	4.1	4.1	3.9	3.9	3.9
VOC (15% O_2)	2.8	2.8	2.8	2.7	2.7	2.8	2.8	2.9	3.0

Table B-10. TEC Bayside Power Station, SC Unit 3A and 3B
CT Fuel Flow Rate Data - General Electric 7241FA CT (Per CT)

A. Natural Gas-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - HHV[1] (MMBtu/hr)	1,960	1,834	1,688	1,572	1,487	1,383	1,255	1,193	1,116
Fuel Rate (lb/hr)	84,521	79,074	72,781	67,796	64,104	59,624	54,119	51,448	48,113
Fuel Rate (10^6 ft^3/hr)	1.913	1.790	1.647	1.534	1.451	1.349	1.225	1.164	1.089
Fuel Rate (lb/sec)	23.478	21.965	20.217	18.832	17.807	16.562	15.033	14.291	13.365

B. Distillate Fuel Oil-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - HHV[1] (MMBtu/hr)	2,139	2,015	1,832	1,735	1,638	1,501	1,353	1,288	1,187
Fuel Rate (lb/hr)	107,764	101,532	92,336	87,438	82,517	75,612	68,180	64,922	59,832
Fuel Rate (10^3 gal/hr)	14.742	13.889	12.631	11.961	11.288	10.343	9.327	8.881	8.185
Fuel Rate (lb/sec)	29.935	28.203	25.649	24.288	22.921	21.003	18.939	18.034	16.620

[1] Includes a 3.5% margin to account for heat rate degradation over time.

Sources: ECT, 2003.
GE, 1998.

Table 6-1. Air Quality Impact Analysis Summary
Bayside Units 1 - 4 (Page 1 of 3)

	Case 1 (100% Load, 18°F Ambient)					Case 2 (75% Load, 18°F Ambient)					Case 3 (50% Load, 18°F Ambient)					Case 4 (100% Load, 59°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
SO_2																				
HSH, 3-Hour ($\mu g/m^3$)	178.2	197.6	179.2	134.4	**217.1**	173.2	167.3	185.5	197.7	215.0	160.8	172.0	154.8	203.6	163.8	169.1	190.3	176.7	146.2	211.5
HSH, 24-Hour ($\mu g/m^3$)	49.0	37.6	43.8	29.5	49.6	50.8	47.4	51.5	44.5	55.8	42.8	47.6	54.1	50.1	**56.4**	45.5	39.0	45.6	32.4	49.4
Annual ($\mu g/m^3$)	1.38	1.38	1.38	1.38	1.38	1.97	1.97	1.97	1.97	1.97	**2.51**	**2.51**	**2.51**	**2.51**	**2.51**	1.50	1.50	1.50	1.50	1.50
NO_2																				
Tier 1 Annual ($\mu g/m^3$)	3.88	3.88	3.88	3.88	3.88	5.40	5.40	5.40	5.40	5.40	**6.86**	**6.86**	**6.86**	**6.86**	**6.86**	4.21	4.21	4.21	4.21	4.21
Tier 2 Annual ($\mu g/m^3$)	2.91	2.91	2.91	2.91	2.91	4.05	4.05	4.05	4.05	4.05	**5.14**	**5.14**	**5.14**	**5.14**	**5.14**	3.16	3.16	3.16	3.16	3.16
PM/PM_{10}																				
HSH, 24-Hour ($\mu g/m^3$)	29.2	27.8	30.6	23.7	0.0	34.8	35.4	41.2	35.7	0.0	48.1	40.7	50.8	45.1	0.0	28.3	30.0	33.2	28.0	0.0
Annual ($\mu g/m^3$)	1.29	1.29	1.29	1.29	1.29	2.33	2.33	2.33	2.33	2.33	3.44	3.44	3.44	3.44	3.44	1.66	1.66	1.66	1.66	1.66
CO																				
HSH, 1-Hour ($\mu g/m^3$)	243.3	268.4	250.7	268.7	270.8	338.3	339.5	321.9	359.5	359.7	545.6	528.2	493.1	580.3	579.8	241.2	262.2	252.6	283.1	271.4
HSH, 8-Hour ($\mu g/m^3$)	113.1	93.2	101.2	77.7	120.9	131.2	125.7	133.4	119.9	154.3	191.8	160.1	176.6	182.7	189.7	99.9	88.2	102.2	85.0	113.1

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Table 6-1. Air Quality Impact Analysis Summary
Bayside Units 1 - 4 (Page 2 of 3)

	Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)					Case 7 (100% Load, 90°F Ambient)					Case 8 (75% Load, 90°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
SO_2																				
HSH, 3-Hour (μg/m^3)	166.8	163.3	178.9	193.6	186.3	155.7	167.5	151.0	196.8	156.3	168.5	178.4	173.1	158.0	200.9	156.7	155.8	168.3	188.8	173.4
HSH, 24-Hour (μg/m^3)	49.6	46.6	51.2	44.8	54.5	41.1	46.4	50.0	48.6	54.6	45.4	40.0	46.1	34.9	49.7	47.2	45.2	50.1	44.3	51.6
Annual (μg/m^3)	2.03	2.03	2.03	2.03	2.03	2.42	2.42	2.42	2.42	2.42	1.56	1.56	1.56	1.56	1.56	2.04	2.04	2.04	2.04	2.04
NO_2																				
Annual (μg/m^3)	5.56	5.56	5.56	5.56	5.56	6.66	6.66	6.66	6.66	6.66	4.39	4.39	4.39	4.39	4.39	5.59	5.59	5.59	5.59	5.59
Tier 2 Annual (μg/m^3)	4.17	4.17	4.17	4.17	4.17	4.99	4.99	4.99	4.99	4.99	3.29	3.29	3.29	3.29	3.29	4.19	4.19	4.19	4.19	4.19
PM/PM_{10}																				
HSH, 24-Hour (μg/m^3)	37.4	36.1	41.8	37.9	0.0	48.6	41.2	51.5	45.2	0.0	29.8	31.9	35.4	30.2	0.0	40.0	37.2	44.4	39.5	0.0
Annual (μg/m^3)	2.52	2.52	2.52	2.52	2.52	3.46	3.46	3.46	3.46	3.46	1.83	1.83	1.83	1.83	1.83	2.69	2.69	2.69	2.69	2.69
CO																				
HSH, 1-Hour (μg/m^3)	335.6	318.0	315.1	356.8	356.6	544.5	529.5	492.7	579.3	578.8	249.7	263.2	257.3	273.2	276.8	346.3	321.4	319.0	368.4	367.9
HSH, 1-Hour (μg/m^3)	129.4	124.7	128.8	119.4	149.3	191.3	160.4	187.9	182.5	188.8	102.2	92.0	104.3	89.6	116.1	131.6	124.6	128.2	122.5	149.0

Table 6-1. Air Quality Impact Analysis Summary
Bayside Units 1 - 4 (Page 3 of 3)

	Case 9 (50% Load, 90°F Ambient)					Maximums
	1992	1993	1994	1995	1996	
SO_2						
HSH, 3-Hour (μg/m^3)	149.1	162.5	146.3	187.4	149.3	**217.1**
HSH, 24-Hour (μg/m^3)	39.6	44.0	47.4	46.9	52.4	**56.4**
Annual (μg/m^3)	2.37	2.37	2.37	2.37	2.37	**2.51**
NO_2						
Annual (μg/m^3)	6.52	6.52	6.52	6.52	6.52	**6.86**
Tier 2 Annual (μg/m^3)	4.89	4.89	4.89	4.89	4.89	**5.14**
PM/PM_{10}						
HSH, 24-Hour (μg/m^3)	47.5	43.0	**52.6**	46.5	0.0	**52.6**
Annual (μg/m^3)	**3.58**	**3.58**	**3.58**	**3.58**	**3.58**	**3.58**
CO						
HSH, 1-Hour (μg/m^3)	654.3	641.2	592.8	**696.6**	696.0	**696.6**
HSH, 8-Hour (μg/m^3)	**224.8**	192.5	221.4	218.1	217.1	**224.8**

	Project Impact	Case No.	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour (μg/m^3)	217.1	1	1996	1,300	1,300	16.7	16.7
HSH, 24-Hour (μg/m^3)	56.4	3	1996	260	365	21.7	15.4
Annual (μg/m^3)	2.51	3	1996	60	80	4.2	3.1
NO_2							
Annual (μg/m^3)	5.14	3	1996	100	100	5.1	5.1
PM_{10}							
HSH, 24-Hour (μg/m^3)	52.6	12	1995	150	150	35.1	35.1
Annual (μg/m^3)	3.58	12	1996	50	50	7.2	7.2
CO							
HSH, 1-Hour (μg/m^3)	696.6	9	1995	40,000	40,000	1.7	1.7
HSH, 8-Hour (μg/m^3)	224.8	9	1992	10,000	10,000	2.2	2.2

Source: ECT, 2003.

THE TAMPA TRIBUNE

Published Daily

Tampa, Hillsborough County, Florida

State of Florida }
County of Hillsborough } ss.

Before the undersigned authority personally appeared C. Pugh, who on oath says that she is the Advertising Billing Supervisor of The Tampa Tribune, a daily newspaper published at Tampa in Hillsborough County, Florida; that the attached copy of advertisement being a

LEGAL NOTICE

in the matter of PUBLIC NOTICE OF INTENT

was published in said newspaper in the issues of

JANUARY 17, 2005

Affiant further says that the said The Tampa Tribune is a newspaper published at Tampa in said Hillsborough County, Florida, and that the said newspaper has heretofore been continuously published in said Hillsborough County, Florida, each day and has been entered as second class mail matter at the post office in Tampa, in said Hillsborough County, Florida for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, this advertisement for publication in the said newspaper.

C. Pugh

Sworn to and subscribed by me, this 19 day of JANUARY, A.D. 20 05

Personally Known ✓ or Produced Identification ____
Type of Identification Produced ____

Susie Lee Slaton

NOTARY PUBLIC STATE OF FLORIDA
OFFICIAL NOTARY SEAL
SUSIE LEE SLATON
COMMISSION NUMBER
DD000060
MY COMMISSION EXP.
APRIL 16, 2005

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 0570040-019-AC / Draft Air Permit No. PSD-FL-301C TECO - H. L. Culbreath Bayside Power Station Hillsborough County, Florida

Applicant: The applicant for this project is the Tampa Electric Company (TECO). The applicant's authorized representative is Mr. Wade A. Maye, General Manager of the H. L. Culbreath Bayside Power Station. The applicant's mailing address is: H. L. Culbreath Bayside Power Station, Tampa Electric Company, P.O. Box 111, Tampa, Florida 33601-0111.

Facility Location: TECO operates the existing H. L. Culbreath Bayside Power Station (formerly the F. J. Gannon Station) in Tampa at 3602 Port Sutton Road in Hillsborough County, Florida.

Project: TECO is permitted to construct four combined cycle gas turbines systems (Bayside Units 1 - 4) to re-power the former F.J. Gannon Station. All six coal-fired Gannon boilers have been permanently shutdown. However, only Bayside Units 1 and 2 have been constructed and are in operation. The applicant proposes a revision of the current PSD air construction permit to add a phase of simple cycle operation and restricted distillate oil firing for the Bayside Unit 3A and 3B gas turbines. In addition, the project will extend the period of time to construct Bayside Units 3 and 4 as combined cycle gas turbine systems.

The existing power plant is a major facility in accordance with Rule 62-212.400, F.A.C., the regulatory program for the Prevention of Significant Deterioration (PSD) of Air Quality. It is located in Hillsborough County, an area that is currently in attainment with the State and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. New projects at this major facility are subject to PSD preconstruction review. Based on a PSD netting analysis that included emissions decreases from the shutdown Gannon boilers as well as emissions increases from the new Bayside Units, the Department concluded that the proposed project requires a determination of the Best Available Control Technology (BACT) for emissions of carbon monoxide (CO), particulate matter (PM/PM10) and volatile organic compounds (VOC). As a result of previous settlement agreements with EPA and the Department, the netting analysis allowed only a portion of the emissions decreases from the shutdown Gannon boilers.

For CO, PM/PM10, and VOC emissions, the Department determined BACT to be the efficient combustion of clean fuels. The proposed gas turbines offer high temperatures, thorough mixing, and sufficient residence time to provide uniform combustion and low emission levels of these pollutants. Fuels are limited to pipeline-quality natural gas and distillate oil with no more than 0.05% sulfur by weight. A water injection system will be used to reduce NOx emissions when firing distillate oil. Only Units 3A and 3B are authorized to fire distillate oil. During simple cycle operations, Units 3A and 3B may fire oil up to 700 full load equivalent hours per year. After conversion to combined cycle operation, Units 3A and 3B are restricted to firing distillate oil only as an emergency backup fuel if natural gas is not available. When Units 3 and 4 are constructed as combined cycle units, selective catalytic reduction (SCR) systems will be installed to reduce nitrogen oxide (NOx) emissions. Each gas turbine will be continuously monitored for emissions of carbon monoxide and nitrogen oxides.

Based on a separate PSD netting analysis, the Department determined that the project requires an air quality impact review for CO and VOC emissions. This netting analysis relied on the full actual emissions decreases from shutdown of the Gannon boilers to reflect expected actual impacts from this project. The project is not subject to an air quality impact review for particulate matter because actual emissions from the plant are expected to decrease by approximately 700 to 1000 tons per year.

No preconstruction monitoring or ambient impact analysis was required for VOC emissions because the potential increase was below the de minimis threshold of 100 tons per year established by rule. A significant impact analysis was conducted for CO emissions. The results predict a maximum 1-hour ambient CO concentration of 696.6 g/m3 and a maximum ambient 8-hour CO concentration of 224.8 g/m3. These levels are well below the regulatory thresholds and impacts from the project are not considered significant. No additional dispersion modeling was necessary. The applicant provided reasonable assurance that the project will not cause or contribute to adverse ambient air quality impacts.

Permitting Authority: Applications for air construction permits are subject to review in accordance with 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 proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114 and fax number is 850/921-9533.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Air Resources Section of the Department's Southwest District Office at 3804 Coconut Palm Drive, Tampa, Florida 33619-8218 (Telephone: 813/744-6100). A copy of the complete project file may also be available at the Air Management Division of the Hillsborough County Environmental Protection Commission at 1900 9th Avenue, Tampa, FL 33605 (Telephone: 813/272-5530).

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked, and all email or facsimile comments must be received by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address, email or facsimile. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. 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 attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority 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 Permitting Authority'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 each 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 state; (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 the 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 Permitting Authority'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 Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

8403 01/17/05

APPENDIX C

DISPERSION MODELING FILES

no small Receipt

SENDER: *COMPLETE THIS SECTION*	*COMPLETE THIS SECTION ON DELIVERY*
■ 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.	A. Signature X Maye ☐ Agent ☑ Addressee B. Received by (*Printed Name*) C. Date of Delivery
1. Article Addressed to: Wade A. Maye, General Manager Tampa Electric Company Bayside / Gannon Station PO Box 111 Tampa, FL 33601-0111	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
(*Transfer from service label*) 7000 2870 0000 7028 3994

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

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:

Mr. Wade A. Maye
General Manager
F. J. Gannon Station
Port Sutton Road - P.O. Box 111
Tampa, FL 33619

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* JC CHAPE
B. Date of Delivery 11-13-03

C. Signature
X
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

NOV 13 2003 33601 DOWNTOWN

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)*
7000 2870 0000 7028 3451

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

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

7000 2870 0000 7028 3451

OFFICIAL USE

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

Postmark Here

Sent To
Wade A. Maye
Street, Apt. No.; or PO Box No.
Port Sutton Rd., - PO Box 111
City, State, ZIP+ 4
Tampa, FL 33619

PS Form 3800, May 2000 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:

Mr. Wade A. Maye
General Manager
F. J. Gannon Station
Port Sutton Road
Tampa, FL 33619

2. 7001 0320 0001 3692 5405

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*)

B. Date of Delivery 8/19/0

C. Signature

X

☐ 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

PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service

CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

7001 0320 0001 3692 5405

OFFICIAL USE

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

Postmark Here

Sent To Wade A. Maye

Street, Apt. No.; or PO Box No. Port Sutton Road

City, State, ZIP+4 Tampa, FL 33619

PS Form 3800, January 2001 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:

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

COMPLETE THIS SECTION ON DELIVERY

A. Signature X [signature] ☒ Agent ☐ Addressee

B. Received by (Printed Name) Benjamin Willoughby

C. Date of Delivery 1/4/05

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 (Transfer from service label) 7000 1670 0013 3109 9014

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

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

OFFICIAL USE

7000 1670 0013 3109 9014

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

Postmark Here

Sent To: Mr. Wade A. Maye, General Manager
Tampa Electric Company
Street, Apt. No.; or PO Box No.: P.O. Box 111
City, State, ZIP+4: Tampa, Florida 33601-0111

PS Form 3800, May 2000 See Reverse for Instructions