STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

Authorized Representative:
Ms. Karen Sheffield, General Manager

Project No. 0570040-015-AC
Air Permit No. PSD-FL-301A
Bayside Power Station
F. J. Gannon Re-Powering Project
Hillsborough County, Florida

Enclosed is final Air Permit No. PSD-FL-301A (Project No. 0570040-015-AC). This permit authorizes construction of eleven new natural gas-fired combined cycle gas turbines that will re-power the existing F. J. Gannon Station. The plant will be renamed the "Bayside Power Station" and will be located within the existing plant boundaries on Tampa's Port Sutton Road in Hillsborough County, Florida. As noted in the attached Final Determination, the Department made only minor changes to the draft permit. 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 C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 1/9/02 to the persons listed:

Ms. Karen Sheffield, TEC Bayside Power Station*
Ms. Cindy Barringer, TEC Bayside Power Station
Mr. Patrick Shell, TEC
Mr. Tom Davis, ECT
Chair, Hillsborough County BCC

Mr. Jerry Campbell, EPC
Mr. Bill Thomas, SWD
Mr. John Notar, NPS
Mr. Gregg Worley, EPA Region 4

Clerk Stamp

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

Victoria Gibson (Clerk) January 9th, 2002 (Date)

PERMITTEE

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

Authorized Representative: Ms. Karen Sheffield, General Manager

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400

PROJECT

Project No. 0570040-015-AC
Air Permit No. PSD-FL-301A

This permit authorizes construction of eleven new combined cycle gas turbines with an approximate electrical production capacity of 2845 MW. The new units will be used to re-power the steam-electrical generators for Units 3, 4, 5, and 6 at the existing F. J. Gannon Station. The re-powered plant will be renamed the "Bayside Power Station". The project will be located within the existing plant boundaries on Tampa's Port Sutton Road in Hillsborough County, Florida. The UTM coordinates are: Zone 17, 360.00 km E, 3087.50 km N.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on November 26, 2001. The applicant published the "Public Notice of Intent to Issue" in The Tampa Tribune on November 30, 2001. The Department received the proof of publication on December 5, 2001. No requests for administrative hearings were filed.

COMMENTS

No comments were received from the general public, the Department's Southwest District Office, the EPA Region 4 office, or the National Park Service. Comments were received from the Environmental Protection Commission of Hillsborough County (EPC). The following discussion provides a summary of the comments and the Department's response.

1. **Technical Evaluation, Page 11**: EPC noted a typographical error in the first sentence. **Response**: The sentence was revised to, "... the applicant did *not* believe the additional controls would provide any measurable reductions in air quality impacts."

2. **Technical Evaluation, Page 14, Low Load Operations and Section III, Specific Condition No. 17(b)**: EPC requested that the gas turbines be limited to operating at or above 50% load at all times except during periods of startup, shutdown or tuning. During periods of startup and shutdown, EPC requested that the number of gas turbines be limited to one per Bayside Unit operating below 50% load. EPC's requests recognize that operation at reduced loads can lead to increased emissions. **Response**: The Tampa Electric Company (TEC) requested low load operation that would allow units to "idle down" during periods of low energy demands. Current Condition No. 17d requires the following for a cold startup, "To minimize emissions, no more than one gas turbine for each Bayside Unit shall be operated during such a startup." The draft permit also grants up to three hours of low load operation in a 24-hour period (excluding startup and shutdown) for each of the gas turbines, *provided the CO and NOx CEMS are properly functioning and the units remain in compliance with the 24-hour emissions standards.* Compliance with the CO and NOx standards provide reasonable assurance that the gas turbine is properly operating in the lean premix combustion mode at reduced loads. Low emissions of particulate matter and volatile organic compounds would correspond to low CO emissions. Sulfur dioxide emissions would be low due to reduced fuel consumption. The Department believes TEC's request is reasonable and the condition was not changed.

3. **Section II, Specific Condition No. 2**: EPC requested that this condition require copies of permit applications also be sent to the EPC. **Response**: The following sentence was added, "Copies shall be provided to the Compliance Authority".

4. **Section II, Specific Condition No. 3**: EPC requested identification as the "Environmental Protection Commission of Hillsborough County". **Response**: The wording was revised.

5. **Section II, Specific Condition No. 11**: EPC requested addition of the rule citation for the definitions of construction and modification (Rule 62-210.200, F.A.C.). **Response**: The rule citation was added.

6. **Section II, Specific Condition No. 18(a)**: EPC requested that the duration of the initial visible emissions tests be extended to 3 hours to remain consistent with 40 CFR 60.11(b) and 40 CFR 60.335(b). **Response**: The NSPS Subpart GG requirements only regulate NOx and SO2 emissions and do not include standards for opacity. The Department believes a 3-hour visible emissions test for each natural gas-fired gas turbine is unnecessary. The condition was not changed.

7. **Section III, Specific Condition No. 14(d) and (g)**: EPC questioned whether an exceedance of the visible emissions or CO standard also means an exceedance for VOC and PM emissions. EPC contended that CO and visible emissions tests are established as surrogates for VOC and PM emissions. The permit states that VOC and PM emissions are expected to be below a certain level (12 lbs/hr for PM and 1.3 ppmvd at 15% oxygen for VOC). EPC requested clarification of the compliance status for PM and VOC if the standards for visible emissions or CO are exceeded. **Response**: The draft permit establishes the firing of pipeline quality natural gas and the efficient combustion design and operation of the gas turbines as BACT for particulate emissions. Compliance with carbon monoxide and visible emissions standards serve as *continuous indicators* of efficient combustion to minimize particulate matter emissions. An exceedance of the CO standard would simply mean that the gas turbine is out of compliance with the CO standard because there is no particulate matter standard specified. Failure to properly maintain and operate the gas turbine or automated control system could be regarded as a separate compliance issue. The response for VOC emissions is similar. To avoid confusion, the permitting notes indicating maximum expected emissions were removed.

8. **Section III, Specific Condition No. 19**: EPC noted a typographical error in the first line on page 13. **Response**: The sentence was corrected to, "… the test methods ~~for~~ are included …"

9. **Section III, Specific Condition No. 25**: EPC requested the addition of the "ammonia injection rate" in the semiannual report for each gas turbine. This would allow EPC to verify the ammonia injection rate was appropriate during periods of NOx monitor downtimes or malfunctions and provide reasonable assurance of proper operation of the NOx control system. **Response**: The following sentence was added, "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."

10. **Section II, Specific Condition Nos. 22, 23, and 24 and Section III, Specific Condition No. 19**: EPC requested that this condition include EPC in any requirements regarding notifications, availability of records, or the submittal of test results. **Response**: The term "Compliance Authority" was substituted for "Department" where appropriate.

The Department also received verbal comments from the applicant regarding the fuel sulfur limit for natural gas. The draft permit included only the NSPS Subpart GG limit of 0.8% sulfur by weight and specified "pipeline-quality" natural gas as the allowable fuel. The applicant requests that the permit include a fuel specification of 2 grains per 100 SCF of natural gas, which was specified in the original PSD permit and in the application for this modification. This would clarify the basis of the Title V fee calculation. **Response**: The Department agrees and made the clarification.

CONCLUSION

The minor revisions noted above and corrections of typographical errors were made to the permit draft. The final action of the Department is to issue the permit with the changes described.

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

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

Authorized Representative:
Ms. Karen Sheffield, General Manager

Project No. 0570040-015-AC
Air Permit No. PSD-FL-301A
Facility ID No. 0570040
SIC No. 4911
Expires: July 1, 2005

PROJECT AND LOCATION

This permit authorizes construction of eleven new combined cycle gas turbines with an approximate electrical production capacity of 2845 MW. The new units will be used to re-power the steam-electrical generators for Units 3, 4, 5, and 6 at the existing F. J. Gannon Station. The re-powered plant will be renamed the "Bayside Power Station". The project will be located within the existing plant boundaries on Tampa's Port Sutton Road in Hillsborough County, Florida. The UTM coordinates are: Zone 17, 360.00 km E, 3087.50 km N.

STATEMENT OF BASIS

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

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A	-	Terminology
Appendix B	-	Final 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

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

1/8/02
Effective Date

PROJECT DESCRIPTION

Upon completion of construction and shutdown of all coal-fired units, the new Bayside Power Station will have an approximate electrical production capacity of 2845 MW based on the nominal capacities for 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.	Emission Unit Description
001	Gannon Unit 1 – existing coal fired boiler with 125 MW steam electrical generator
002	Gannon Unit 2 – existing coal fired boiler with 125 MW steam electrical generator
003	Gannon Unit 3 – existing coal fired boiler with 180 MW steam electrical generator
004	Gannon Unit 4 – existing coal fired boiler with 188 MW steam electrical generator
005	Gannon Unit 5 – existing coal fired boiler with 239 MW steam electrical generator
006	Gannon Unit 6 – existing coal fired boiler with 414 MW steam electrical generator
008	Gannon Station Coal Yard – Serves existing Gannon Units 1 – 6
020	Bayside Unit 1A – 169 MW combined cycle gas turbine fired with natural gas
021	Bayside Unit 1B – 169 MW combined cycle gas turbine fired with natural gas
022	Bayside Unit 1C – 169 MW combined cycle gas turbine fired with natural gas
023	Bayside Unit 2A – 169 MW combined cycle gas turbine fired with natural gas
024	Bayside Unit 2B – 169 MW combined cycle gas turbine fired with natural gas
025	Bayside Unit 2C – 169 MW combined cycle gas turbine fired with natural gas
026	Bayside Unit 2D – 169 MW combined cycle gas turbine fired with natural gas
027	Bayside Unit 3A – 169 MW combined cycle gas turbine fired with natural gas
028	Bayside Unit 3B – 169 MW combined cycle gas turbine fired with natural gas
029	Bayside Unit 4A – 169 MW combined cycle gas turbine fired with natural gas
030	Bayside Unit 4B – 169 MW combined cycle gas turbine fired with natural gas

Notes:

a. Gannon Unit 5 (EU 005) must be shutdown before operating Bayside Unit 1 (EUs 020, 021, and 022).
b. Gannon Unit 6 (EU 006) must be shutdown before operating Bayside Unit 2 (EU 023, 024, 025, and 026).
c. Gannon Unit 3 (EU 003) must be shutdown before operating Bayside Unit 3 (EU 027 and 028).
d. Gannon Unit 4 (EU 004) must be shutdown before operating Bayside Unit 4 (EU 029 and 030).
e. EUs 001, 002, 003, 004, 005, and 006 must be shut down before January 1, 2005. The Department expects that other coal-related activities will also cease operation shortly after the shutdown of these coal-fired boilers.

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). Based on the available information, this project is not subject to the requirements of a 112(g) case-by-case determination of the Maximum Available Control Technology (MACT).

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

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

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

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

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

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

RELEVANT DOCUMENTS

- DEP/TEC Consent Final Judgment signed on December 7, 1999.
- EPA/TEC Consent Decree entered on October 5, 2000.
- PSD permit application (Bayside Units 1 and 2) received on September 21, 2000 and all related correspondence.
- Original PSD air construction Permit No. PSD-FL-301 issued on March 30, 2001.
- PSD permit application (Bayside Units 3 and 4) received on June 26, 2001 and all related correspondence.

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 and phone number 850/488-0114. Copies shall also be provided to the 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, 1410 North 21 Street, Tampa, FL 33605. The phone number is 813/272-5530 and the fax number is 813/272-5605. 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. The phone number is 813/744-6100 and the fax number is 813/744-6084.
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/TEC Consent Final Judgment or the EPA/TEC 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/TEC Consent Final Judgment or the EPA/TEC 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 may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 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.]

A. COMBINED CYCLE GAS TURBINES

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

Emissions Units 020 – 030: Combined Cycle Gas Turbines

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			
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	11 GTs	1859 MW	4 STs	986	2845

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. Schedule: Bayside Unit 1 is scheduled for completion in May of 2003 and Bayside Units 2, 3, and 4 are scheduled for completion in May of 2004. The permittee shall inform the Department and Compliance Authority of any substantial changes to the construction schedule. [Application; Rule 62-212.400(BACT), F.A.C.]

4. Combined Cycle Gas Turbines: The permittee is authorized to install, tune, operate and maintain eleven 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): The preliminary design of the HRSGs provides three levels of steam conditions when firing natural gas (high pressure, intermediate pressure, and low pressure). The permittee shall submit the final design data with the Title V application. [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/TEC Consent Final Judgment; EPA/TEC Consent Decree; Rule 62-4.070(3), F.A.C.]

9. Evaporative Inlet Air-Cooling System: Each gas turbine may have an evaporative cooling system designed to reduce the temperature of the inlet air to the gas turbine compressor. The reduced temperature provides a greater mass flow rate and increases power production with additional fuel combustion. The preliminary

design is for a water distribution system with packed media blocks of corrugated layers of fibrous material. Air passing over the system wicks moisture away from the media to create the cooling effect. The permittee shall submit the final design data with the Title V application. [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).

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

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 No. 22 in this section, each SCR system shall be designed and operated for an ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. [Rule 62-4.070(3), F.A.C.]

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

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

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

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

f. **Visible Emissions**: Visible emissions shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. Except as allowed by Condition No. 17 of this section, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]

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

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).

 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. 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 documented malfunction of a gas turbine. 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, and documented malfunction, each gas turbine is allowed up to three hours of operation below 50% base load in any 24-hour block, providing: the gas turbine is firing natural gas; 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 based on 24-hour block averages of valid CEMS data.

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

(1) *Startup, Shutdown, and Malfunction*: Periods of data excluded for gas turbine startup (excluding steam turbine cold startup), shutdown, or documented malfunction shall not exceed four 1-hour emission averages in any 24-hour block due to all such episodes. Gas turbine startup is the commencement of operation of a gas turbine that has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, or pollution control device imbalances, which may result in elevated emissions. Shutdown is the process of bringing a gas turbine off line and ending fuel combustion. A malfunction is 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. A documented malfunction is a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

(2) *Steam Turbine Cold Startup*: Periods of data excluded for a steam turbine cold startup shall not exceed sixteen 1-hour emission averages in any 24-hour block. A "steam turbine cold startup" is defined as 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. Based on actual operating data and experience, the Department may modify this period of data exclusion in the Title V air operation permit without modifying this PSD permit.

(3) *Tuning*: If the permittee provides at least five days advance notice prior to a major tuning session performed by the manufacturer's representative, monitoring data during tuning may be excluded from the 24-hour block compliance averages. Periods of data excluded for such episodes shall not exceed a total of three 1-hour averages in any 24-hour block. Tuning sessions must be performed in accordance with the manufacturer's recommendations. {Permitting Note: As an example, a major tuning session would occur after a combustor change-out. A tuning session may take a few hours each day over a few days. No more than two major tuning sessions would be expected during any year.}

If a CEMS reports emissions in excess of a CO or NOx standard, 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.

d. **Startup and Shutdown Plan**: A "steam turbine cold startup" is defined as 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 for each Bayside Unit shall be operated during each steam turbine cold startup. The permittee shall notify the Compliance Authority at least 24 hours in advance of a steam turbine cold startup. For each Bayside Unit, the permittee shall provide a Startup and Shutdown Plan as part of the application for a Title V air operation permit. The plan shall identify startup and shutdown procedures, the duration of each procedure, and the methods used to minimize emissions during these periods. Within 90 days of completing eight steam turbine cold startups following commencement of commercial operation or within 90 days after 12 months of commercial operation (whichever occurs first), the permittee shall submit a revised plan to the Department based on actual operating data and experience. The Department shall review the actual operational data and determine whether data exclusion allowed for a steam turbine cold startup defined in Condition 23 of this section shall be modified to represent good operational practices. The Department shall also evaluate the operational information and determine whether a separate "warm startup" requirement shall be specified in the Title V operation permit for startup after the steam turbine has been offline for 24 hours or more, but less than 48 hours.

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. [Design; Rules 62-210.700(5), 62-4.130, and Rule 62-212.400 (BACT), F.A.C.]

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 is 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 No. 17 of this section. All periods of data excluded due to startup, shutdown or malfunction shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited. Excluded emissions shall be summarized in the required semiannual report.

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

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

f. *Monitor Availability.* Monitor availability shall not be less than 95% in any calendar quarter. The report required in Condition 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; 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.]

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

EU ID	Emission Unit Description
001	Gannon Unit 1 – existing coal fired boiler with 125 MW steam electrical generator
002	Gannon Unit 2 – existing coal fired boiler with 125 MW steam electrical generator
003	Gannon Unit 3 – existing coal fired boiler with 180 MW steam electrical generator
004	Gannon Unit 4 – existing coal fired boiler with 188 MW steam electrical generator
005	Gannon Unit 5 – existing coal fired boiler with 239 MW steam electrical generator
006	Gannon Unit 6 – existing coal fired boiler with 414 MW steam electrical generator
008	Gannon Station Coal Yard – Serves existing Gannon Units 1 – 6

SHUTDOWN REQUIREMENTS

1. Shutdown of Coal-Fired Gannon Units

   a. *Shutdown of Gannon Unit 3*: The Gannon Unit 3 (EU 003) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 3 gas turbine (EU 027 and EU 028). Upon first fire in any Bayside Unit 3 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 9.06 x 10^{+06} MMBtu per calendar year.

   b. *Shutdown of Gannon Unit 4*: The Gannon Unit 4 (EU 004) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 4 gas turbine (EU 029 and EU 030). Upon first fire in any Bayside Unit 4 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 8.70 x 10^{+06} MMBtu per calendar year.

   c. *Shutdown of Gannon Unit 5*: The Gannon Unit 5 (EU 005) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 1 gas turbine (EU 020 – EU 022). Upon first fire in any Bayside Unit 1 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 13.2 x 10^{+06} MMBtu per calendar year.

   d. *Shutdown of Gannon Unit 6*: The Gannon Unit 6 (EU 006) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 2 gas turbine (EU 023 – EU 026). Upon first fire in any Bayside Unit 2 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 21.4 x 10^{+06} MMBtu per calendar year.

   e. *Shutdown of Gannon Units 1 - 6*: The permittee shall shutdown and cease any and all operation of coal-fired Gannon Units 1 through 6 (EU 001 - 006) no later than December 31, 2004. "Shutdown" shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel (including wood-derived fuel) nor produce any steam for electricity production, other than through re-powering as specified in this permit.

   [Rule 62-212.400(BACT), F.A.C.; EPA/TEC Consent Decree]

2. Permanent Bar on Combustion of Coal: Commencing on January 1, 2005, the permittee shall not combust coal in the operation of any unit at this plant. [EPA/TEC Consent Decree]

3. Notification: Before January 1, 2005, the permittee shall notify the Department and Compliance Authority of plans for the coal storage and handling facilities. Additional permits may be required. [Rule 62-210.300, F.A.C.]

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

TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

CCGT	-	Combined Cycle Gas Turbine
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

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Table B-1. Emissions Standards for Bayside Units 1 - 4
Eleven General Electric Model PG7241(FA) Combined Cycle Gas Turbines Firing Natural Gas

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

Notes:

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

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

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

FINAL BACT DETERMINATIONS

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

The project did result in significant net actual emissions increases of carbon monoxide (CO) and volatile organic compounds (VOC). Based on an interpretation by EPA Region 4, emissions of particulate matter (PM/PM_{10}) would also be significant if BACT-level controls had previously been installed on the existing Gannon Units. For CO, PM/PM_{10}, and VOC emissions, the Department determines that the efficient combustion of pipeline-quality natural gas and good operating practices represent BACT for the combined cycle units. In addition to the control requirements, the CO, PM/PM_{10}, and VOC emissions standards specified in the permit and summarized in Table B-1 represent the determination of Best Available Control Technology (BACT). A continuous emission monitoring system (CEMS) is required to demonstrate continuous compliance with the CO standards. The CO CEMS will also serve as a continuous indicator of efficient combustion to minimize PM and VOC emissions. The Department's detailed technical review and rationale for the determinations of Best Available Control Technology (BACT) are presented in Technical Evaluation and Preliminary Determination issued with the draft permit package.

Determination By:

Jeffery F. Koerner (signature) 1-8-02

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

Recommended By:

A. A. Linero (signature) 1/8/02

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

Approved By:

Howard L. Rhodes (signature) 1/8/02

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

SUMMARY OF MASS EMISSIONS RATES

Table E-1. Summary of Mass Emission Rates Vs. Compressor Inlet Temperatures

Pollutant	Compressor Inlet Temperature	Mass Emission Rate lb/hour
CO	18° F	31.1
	35° F	30.0
	59° F	28.7
	72° F	27.8
	93° F	26.9
NOx	18° F	24.7
	35° F	23.8
	59° F	23.1
	72° F	22.6
	93° F	21.9
PM/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.
- 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

[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

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

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

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

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

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

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

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

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

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

Department requirement: **The permit species sulfur monitoring methods.**

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

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

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:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Ronald Toellner B. Date of Delivery 4-11-02

C. Signature
X Ron Toellner ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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

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

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 3109

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)

OFFICIAL USE

7000 2870 0000 7028 3109

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

Postmark Here

Sent To
Karen Sheffield
Street, Apt. No.; or PO Box No.
Port Sutton Road
City, State, ZIP+ 4
Tampa, FL 33619

PS Form 3800, May 2000 **See Reverse for Instructions**

TAMPA ELECTRIC

December 4, 2001

Mr. Clair Fancy
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via Fed Ex
Airbill No. 7902 3411 2545

Re: Tampa Electric Company (TEC)
Bayside Power Station
Air Construction Permit
DEP File No. 0570040-015-AC (PSD-FL-301A)

Dear Mr. Fancy:

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 Friday, November 30 2001. If you have any questions, please feel free to telephone Shannon Todd or me at (813) 641-5125.

Sincerely,

Laura R. Crouch

Laura R. Crouch
Manager - Air Programs
Environmental Affairs

EA/bmr/SKT296

Enclosure

c(enc): Mr. Tom Davis - ECT
Mr. Jerry Campbell, EPCHC
Mr. Buck Oven, FDEP
Mr. Scott Sheplak, FDEP
Mr. Jerry Kissel - FDEP SW
Mr. John Bunyak - NPS

THE TAMPA TRIBUNE
Published Daily
Tampa, Hillsborough County, Florida

RECEIVED
DEC 05 2001
BUREAU OF AIR REGULATION

State of Florida }
County of Hillsborough } ss.

Before the undersigned authority personally appeared J. Rosenthal, who on oath says that she is Classified Billing Manager 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 NOVEMBER 30, 2001

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.

J Rosenthal

Sworn to and subscribed by me, this 30 day

of NOVEMBER, A.D. 20 01

Personally Known ✓ or Produced Identification ______
Type of Identification Produced ______

NOTARY PUBLIC STATE OF FLORIDA
OFFICIAL NOTARY SEAL
SUSIE LEE SLATON
COMMISSION NUMBER
DD000060
MY COMMISSION EXP.
APRIL 16, 2005

Susie Lee Slaton

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
Tampa Electric Company Bayside Power Station, Gannon Re-Powering Project
Project No. 0570040-015-AC
Draft Permit PSD-FL-301A

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Tampa Electric Company to re-power the existing F. J. Gannon power plant on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and will have a nominal electrical production capacity of 2845 MW. The applicant's authorized representative is Ms. Karen Sheffield, the General Manager of the Bayside Power Station. The applicant's mailing address is Bayside Power Station, Port Sutton Road, Tampa, FL 33619.

The applicant proposes to re-power the existing Gannon Station with eleven new combined cycle gas turbines. Each new unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. The new combined cycle units will be grouped to re-power the existing steam-electric turbines for existing Gannon Units 3,4,5, and 6. The re-powering project will increase the nominal electrical generating capacity of this plant to 2845 MW. The overall thermal efficiency of the plant is predicted to increase from approximately 30% to 55%. All existing Gannon coal-fired boilers will be shut down prior to January 1, 2005.

Because the existing plant is a PSD-major source of air pollution, new projects are subject to the preconstruction review requirements for the Prevention of Significant Deterioration (PSD) of Air Quality in Rule 62-212.400, F.A.C. The re-powering project will result in the following potential annual emissions: 1383 tons per year of carbon monoxide; 1113 tons per year of nitrogen oxides (NOx), 1.4 tons per year of lead, 368 tons per year of particulate matter (PM/PM10), 89 tons per year of sulfuric acid mist (SAM), 487 tons per year sulfur dioxide (SO2), and 135 tons per year of volatile organic compounds (VOC). The project is significant for emissions of CO, PM/PM10, and VOC. Due to the large emissions reductions from the shutdown of the existing coal-fired boilers, the project nets out of PSD review for emissions of NOx SAM, and SO2. After the shutdown of all coal-fired units, the re-powering project will reduce emissions of: nitrogen oxides by more than 28,000 tons per year; particulate matter by more than 1600 tons per year; sulfur dioxide by more than 60,000 tons per year; sulfuric acid mist by more than 900 tons per year; and lead by more than 18 tons per year.

The Department is required to determine the Best Available Control Technology (BACT) for the significant emissions of CO, PM/PM10, and VOC. For each of these pollutants, BACT is determined to be the efficient combustion design and exclusive firing of pipeline-quality natural gas. A continuous emissions monitoring system (CEMS) will be used to demonstrate compliance with the CO emissions standards and serve as an indicator of efficient combustion to minimize emissions of PM/PM10 and VOC.

The gas turbines incorporate dry low-NOx combustion technology and automated controls to minimize NOx emissions. The state and federal settlement agreements require the installation of a selective catalytic reduction (SCR) system to reduce NOx emissions. A continuous emissions monitoring system (CEMS) is required for acid rain monitoring and will be used to demonstrate compliance with the NOx emissions standard. The exclusive firing of pipeline-quality natural gas minimizes emissions of sulfuric acid mist (SAM) and SO2. Based on the most recent HAP emissions data available, the project does not trigger a 112(g) case-by-case MACT determination.

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

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

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

Mediation is not available in this proceeding.

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

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

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

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

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

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southwest District Office
Air Resources
3804 Coconut Palm Drive
Tampa, FL 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Hillsborough County Environmental Protection Commission
Air Management Division
1410 North 21 Street
Tampa, FL 33605
813/272-5530
Fax: 813/272-5605

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

3919 11/30/01

Memorandum

Florida Department of Environmental Protection

Jeff

TO: Howard Rhodes

THRU: Clair Fancy
Al Linero

FROM: Jeff Koerner

DATE: January 8, 2002

SUBJECT: Final Air Permit No. PSD-FL-301A
Project No. 0570040-015-AC
Tampa Electric Company, Bayside Power Station
F.J. Gannon Station Re-Powering Project

Attached is the Final Permit that authorizes construction of eleven new natural gas-fired combined cycle combustion turbines to re-power the existing F.J. Gannon Station. The existing plant is renamed the "Bayside Power Station" and is located within the existing plant boundaries on Tampa's Port Sutton Road in Hillsborough County, Florida.

We distributed an "Intent to Issue Permit" package on November 26, 2001. The applicant published the "Public Notice" in The Tampa Tribune on November 30, 2001 and we received proof of publication on December 5, 2001. During the 30-day comment period, we received comments from the Environmental Protection Commission of Hillsborough County. As noted in the attached Final Determination, we made only minor changes to the draft permit.

Day 90 for this project is February 18, 2002. I recommend your approval and signature of the attached Final Permit.

Attachments

HLR/CHF/AAL/jfk

Best Available Copy

ADMINISTRATIVE OFFICES, LEGAL & WATER MANAGEMENT DIVISION
1900 - 9TH AVENUE
TAMPA, FLORIDA 33605
TELEPHONE (813) 272-5960
FAX (813) 272-5157

AIR MANAGEMENT DIVISION
TELEPHONE (813) 272-5530
WASTE MANAGEMENT DIVISION
TELEPHONE (813) 272-5788
WETLANDS MANAGEMENT DIVISION
TELEPHONE (813) 272-7104

ENVIRONMENTAL PROTECTION COMMISSION
of Hillsborough County

FAX Transmittal Sheet

DATE: Dec 10, 2001

TO: Jeff Koerner

FAX Phone: 850-922-6979 Voice Phone: 850-921-9536

TOTAL NUMBER OF PAGES INCLUDING THIS COVER PAGE: 4

EPC FAX Transmission Line: (813) 272-5605
For retransmission or any FAX problems, call:
(813) 272-5530 ext. 1288

FROM: Bob Walck

(Circle applicable section below)

Air Division

-Compliance -Enforcement/Analysis

-Monitoring/Toxics -Permitting

SPECIAL INSTRUCTIONS:

ENVIRONMENTAL PROTECTION COMMISSION HILLSBOROUGH COUNTY

ADMINISTRATIVE OFFICES, LEGAL & WATER MANAGEMENT DIVISION
THE ROGER P. STEWART ENVIRONMENTAL CENTER
1900 - 9TH AVENUE • TAMPA, FLORIDA 33605
PHONE (813) 272-5960 • FAX (813) 272-5157

AIR MANAGEMENT DIVISION
FAX (813) 272-5605
WASTE MANAGEMENT DIVISION
FAX (813) 276-2256
WETLANDS MANAGEMENT DIVISION
FAX (813) 272-7144
1410 N. 21ST STREET • TAMPA, FLORIDA 33605

December 10, 2001

Jeff Koerner
Department of Environmental Protection, Bureau of Air Regulation
2600 Blair Stone Road
Mail Station 5505
Tallahassee, FL 32399-2400

Re: Hillsborough County - AP
DEP File No. 0570040-015-AC
PSD-FL-301A

Dear Mr. Koerner:

Thank you for forwarding a copy of the Draft construction permit for Bayside Units 3 and 4 to EPC staff for review. After reviewing the draft construction permit, EPC staff offer the following comments for your consideration:

1. <u>Technical Evaluation, Page 11, first sentence</u>
Please verify the wording of the first complete sentence on this page. In reading the first sentence, it seems the sentence should state the applicant did **not** believe the additional controls would provide any measurable reductions in air quality impacts, when considering the context of the paragraph.

2. <u>Technical Evaluation, Page 14, Low Load Operations and Section III, Specific Condition No. 17(b)</u>
EPC staff is concerned this condition could be read to authorize the operation of all CTs at less than 50% load for three hours during any 24 hour period. Therefore, during any 24 hour period, the potential exists for a total of 33 hours of operation (all eleven CTs combined) below 50% load. EPC staff requests the CTs be limited to operating at or above 50% load at all times except during periods of CT startup and shutdown or tuning. During periods of CT startup and shutdown, EPC staff requests the number of CTs operating be limited to one CT per Bayside Unit operating below 50% load. EPC makes this request because as CTs are operated at reduced percentages of the maximum load the emission rates increase. EPC staff has determined it would be unreasonable to authorize the operation of a single CT at less than 50% load

BEST AVAILABLE COPY

for a period of 33 hours which is equivalent to the condition as it is currently written. Specific Condition No. 13 states that the BACT relies on "good operating practices". EPC staff does not agree that authorizing the operation of eleven CTs at less than 50% load for up to three hours during any 24 hour period each represents good operating practices. Additionally, the draft permit requires the facility to remain in compliance with the emission limits of the permit, the permittee has not provided reasonable assurance a violation will not occur while operating at less than 50% load. Appendix C of the original permit application lists emission rates for operation between 50 and 100% load, but not less than 50% load.

3. <u>Section II, Specific Condition No. 2</u>
Please include notification to the Environmental Protection Commission of Hillsborough County as well as the Department.

4. <u>Section II, Specific Condition No. 3</u>
Please correct the title of the EPC. It should read "Environmental Protection Commission of Hillsborough County".

5. <u>Section II, Specific Condition No. 11</u>
Please include the rule quote for the definitions of construction and modification (Rule 62-210.200, F.A.C.).

6. <u>Section II, Specific Condition No. 18(a)</u>
The condition states the visible emission test shall be 30 minutes in duration. EPC staff request the duration of the initial visible emissions tests be extended to 3 hours to remain consistent with 40 CFR 60.11(b) and 40 CFR 60.335(b).

7. <u>Section III, Specific Condition No. 14(d)</u>
Since a satisfactory visible emissions test and CO limits are used as surrogates for VOC and PM emissions, if an exceedance of the visible emissions standard or an exceedance of the CO standard occurs does this also mean that TEC has also had exceedances for VOC and PM as well? Please note, the permit states that VOC and PM emissions are expected to be below a certain level (12 lbs/hr for PM and 1.3 ppmvd at 15% oxygen for VOC). Also the Technical Evaluation lists potential emissions of PM and VOC of 367.9 tpy and 134.9 tpy respectively for Bayside Units 1 through 4. Please clarify the compliance status of the facility in case of visible emissions or CO exceedances with respect to PM and VOC.

8. <u>Section III, Specific Condition No. 19</u>
In the first line on page 13, please clarify the wording. EPC staff believe the sentence should read, "...the test methods ~~for~~ are included...".

9. <u>Section III, Specific Condition No. 25</u>
Please include in the semiannual reports the ammonia injection

BEST AVAILABLE COPY

rate, or range, for the period addressed in each report for each CT. This will allow EPC staff to verify the ammonia injection rate was appropriate during periods of NOx monitor downtimes or malfunctions and provide reasonable assurance the system will perform adequately.

10. Section II, Specific Condition Nos. 22, 23, and 24 and Section III, Specific Condition No. 19
Please include the Environmental Protection Commission of Hillsborough County in any references to the availability of records or the requirement for special tests.

If you have any questions, please feel free to contact Rob Kalch at (813) 272-5530.

Sincerely,

Alice H Harman

Alice H. Harman, P.E.
Chief, Air Permitting Section

cc: Ms. Karen Sheffield, General Manager, TEC-Bayside Power Station

Memorandum

Florida Department of
Environmental Protection

TO: Clair Fancy, Chief – Bureau of Air Regulation aaz for CHF

THROUGH: Al Linero, Administrator - New Source Review Section aaz

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

DATE: November 16, 2001

PROJECT: Tampa Electric Company
Bayside Power Station - Gannon Re-Powering Project
Project No. 0570040-015-AC
Draft Permit No. PSD-FL-301A

Attached is the intent to issue permit and public notice package to re-power the existing Gannon power plant located on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and consist of eleven new natural gas-fired combined cycle gas turbine that will re-power the existing steam-electrical generators for existing Gannon Units 3 through 6. The nominal electric generating capacity for this site will increase from approximately 1300 MW to 2800 MW. The attached P.E. certification provides a brief summary of the required controls and emissions standards. The attached Technical Evaluation and Preliminary Determination provides a detailed analysis of the project.

Day #74 of the permitting time clock is January 11, 2002. I recommend your approval of the attached Draft Permit package.

CHF/AAL/jfk
Attachments

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400

P.E. CERTIFICATION STATEMENT

PERMITTEE

Tampa Electric Company
Bayside Power Station, Gannon Re-Powering Project
Port Sutton Road
Tampa, FL 33619

Project No. 0570040-015-AC
Draft Permit No. PSD-FL-301A
Facility ID No. 0570040
SIC No. 4911

PROJECT DESCRIPTION

The applicant, Tampa Electric Company, owns and operates the F.J. Gannon Station located on Tampa's Port Sutton Road in Hillsborough County, Florida. The applicant proposes to re-power the existing Gannon Station with eleven new combined cycle gas turbines in accordance with the DEP/TEC Consent Final Judgment and with the EPA/TEC Consent Decree. Each combined cycle unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. The new combined cycle units will be grouped to re-power the steam-electric turbines for existing Gannon Units 3, 4, 5, and 6. The re-powering project will increase the nominal electrical generating capacity of this plant from 1285 MW to 2845 MW. All existing Gannon coal-fired boilers will be shut down prior to January 1, 2005.

The project will result in significant net increases in actual emissions of CO and VOC. Based on EPA Region 4's interpretation of netting for this project, it is also significant for emissions of PM/PM_{10}. The Best Available Control Technology (BACT) for each of these pollutants is determined to be the efficient combustion design and operation combined with the exclusive firing of pipeline-quality natural gas. The CO BACT standard is specified as 9.0 ppmvd @15% oxygen based on a 24-hour block average as determined by CEMS data. Due to the very low uncontrolled emission rates, no emissions standards are specified for PM/PM_{10} and VOC. Instead, the CO CEMS will serve as a continuous indicator of efficient combustion to minimize emissions of these pollutants. The state and federal settlement agreements require the installation of SCR systems to reduce NOx emissions to 3.5 ppmvd @ 15% oxygen or less. A NOx CEMS is required for acid rain monitoring and will be used to demonstrate compliance with the emissions standard based on a 24-hour block average. The exclusive firing of pipeline-quality natural gas minimizes potential emissions of sulfuric acid mist (SAM) and SO_2. Based on the most recent HAP emissions data available, the project does not trigger a 112(g) case-by-case MACT determination.

After shutdown of all coal-fired units prior to 2005, it is estimated that the Bayside project will reduce *actual* emissions of: nitrogen oxides by more than 28,000 tons per year; particulate matter by more than 1400 tons per year; sulfur dioxide by more than 60,000 tons per year; sulfuric acid mist by more than 900 tons per year; and lead by more than 18 tons per year. The project will increase *potential* emissions of carbon monoxide and volatile organic compounds. However, based on recent stack test data for the General Electric Model PG7241(FA) gas turbine, actual CO and VOC emissions will likely be less than half of the allowable emissions, which would result in actual emission decreases for these pollutants as well. Although not specifically required for all pollutants, the emissions standards specified in the draft permit for CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC represent BACT-level controls consistent with other recent combined cycle gas turbine projects.

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

Jeffery J. Koerner

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

11-16-01
(Date)

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

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 16, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Project No. 0570040-015-AC
Draft Permit No. PSD-FL-301A
Draft PSD Permit for the Bayside Power Station
Revised Gannon Re-Powering Project

Dear Ms. Sheffield:

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

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

Please submit any written comments you wish to have considered concerning the Department's proposed action to the Administrator of the New Source Review Section, A. A. Linero, at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/921-9536.

Sincerely,

11/21

for C. H. Fancy, Chief
Bureau of Air Regulation

CHF/AAL/jfk

Enclosures

In the Matter of an
Application for Air Permit by:

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

Project No. 0570040-015-AC
Draft Permit No. PSD-FL-301A
Bayside Power Station
Hillsborough County, Florida

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. The applicant, Tampa Electric Company, applied on June 26, 2001 to the Department for a permit to re-power the existing F.J. Gannon power plant located on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station. The Draft Permit requires the shutdown of existing coal-fired units and authorizes the construction of eleven new combined cycle gas turbine units. The proposed permit includes determinations of the Best Available Control Technology (BACT) for emissions of carbon monoxide, particulate matter, and volatile organic compounds.

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

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

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

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

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

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

11/21

for C. H. Fancy, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11/26/01 to the persons listed:

Ms. Karen Sheffield, Bayside*
Mr. Patrick Shell, Bayside
Mr. Adriano Alcoz, Bayside
Mr. Tom Davis, ECT
Chair, Hillsborough County BCC
Mr. Jerry Campbell, HEPC
Mr. Gerald Kissel, SWD
Mr. John Notar, NPS
Mr. Gregg Worley, EPA Region 4

Clerk Stamp

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

Victoria Gibson 11/26/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Tampa Electric Company
Bayside Power Station, Gannon Re-Powering Project
Project No. 0570040-015-AC
Draft Permit PSD-FL-301A

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Tampa Electric Company to re-power the existing F. J. Gannon power plant on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and will have a nominal electrical production capacity of 2845 MW. The applicant's authorized representative is Ms. Karen Sheffield, the General Manager of the Bayside Power Station. The applicant's mailing address is Bayside Power Station, Port Sutton Road, Tampa, FL 33619.

The applicant proposes to re-power the existing Gannon Station with eleven new combined cycle gas turbines. Each new unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. The new combined cycle units will be grouped to re-power the existing steam-electric turbines for existing Gannon Units 3, 4, 5, and 6. The re-powering project will increase the nominal electrical generating capacity of this plant to 2845 MW. The overall thermal efficiency of the plant is predicted to increase from approximately 30% to 55%. All existing Gannon coal-fired boilers will be shut down prior to January 1, 2005.

Because the existing plant is a PSD-major source of air pollution, new projects are subject to the preconstruction review requirements for the Prevention of Significant Deterioration (PSD) of Air Quality in Rule 62-212.400, F.A.C. The re-powering project will result in the following potential annual emissions: 1383 tons per year of carbon monoxide; 1113 tons per year of nitrogen oxides (NOx), 1.4 tons per year of lead, 368 tons per year of particulate matter (PM/PM_{10}), 89 tons per year of sulfuric acid mist (SAM), 487 tons per year sulfur dioxide (SO_2), and 135 tons per year of volatile organic compounds (VOC). The project is significant for emissions of CO, PM/PM_{10}, and VOC. Due to the large emissions reductions from the shutdown of the existing coal-fired boilers, the project nets out of PSD review for emissions of NOx, SAM, and SO_2. After the shutdown of all coal-fired units, the re-powering project will reduce emissions of: nitrogen oxides by more than 28,000 tons per year; particulate matter by more than 1600 tons per year; sulfur dioxide by more than 60,000 tons per year; sulfuric acid mist by more than 900 tons per year; and lead by more than 18 tons per year.

The Department is required to determine the Best Available Control Technology (BACT) for the significant emissions of CO, PM/PM_{10}, and VOC. For each of these pollutants, BACT is determined to be the efficient combustion design and exclusive firing of pipeline-quality natural gas. A continuous emissions monitoring system (CEMS) will be used to demonstrate compliance with the CO emissions standards and serve as an indicator of efficient combustion to minimize emissions of PM/PM_{10} and VOC.

The gas turbines incorporate dry low-NOx combustion technology and automated controls to minimize NOx emissions. The state and federal settlement agreements require the installation of a selective catalytic reduction (SCR) system to reduce NOx emissions. A continuous emissions monitoring system (CEMS) is required for acid rain monitoring and will be used to demonstrate compliance with the NOx emissions standard. The exclusive firing of pipeline-quality natural gas minimizes emissions of sulfuric acid mist (SAM) and SO_2. Based on the most recent HAP emissions data available, the project does not trigger a 112(g) case-by-case MACT determination.

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

The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair

Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

Mediation is not available in this proceeding.

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

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

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

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

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

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southwest District Office
Air Resources
3804 Coconut Palm Drive
Tampa, FL 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Hillsborough County Environmental
Protection Commission
Air Management Division
1410 North 21 Street
Tampa, FL 33605
Telephone: 813/272-5530
Fax: 813/272-5605

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Bayside Power Station
Gannon Re-Powering Project

Project No. 0570040-015-AC
Draft Permit No. PSD-FL-301A

COUNTY

Hillsborough County

APPLICANT

Tampa Electric Company
Port Sutton Road
Tampa, FL 33619

PERMITTING AUTHORITY

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

November 16, 2001

Filename: 301A TEPD.doc

TABLE OF CONTENTS

This document describes the overall project, identifies applicable air pollution regulations, provides the rationale for draft determinations of the Best Available Control Technology, establishes emissions standards, presents a review of the air quality impact analysis, and makes a preliminary determination to issue the air permit. It is organized by the following sections.

1. APPLICATION INFORMATION

Applicant Name and Address

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

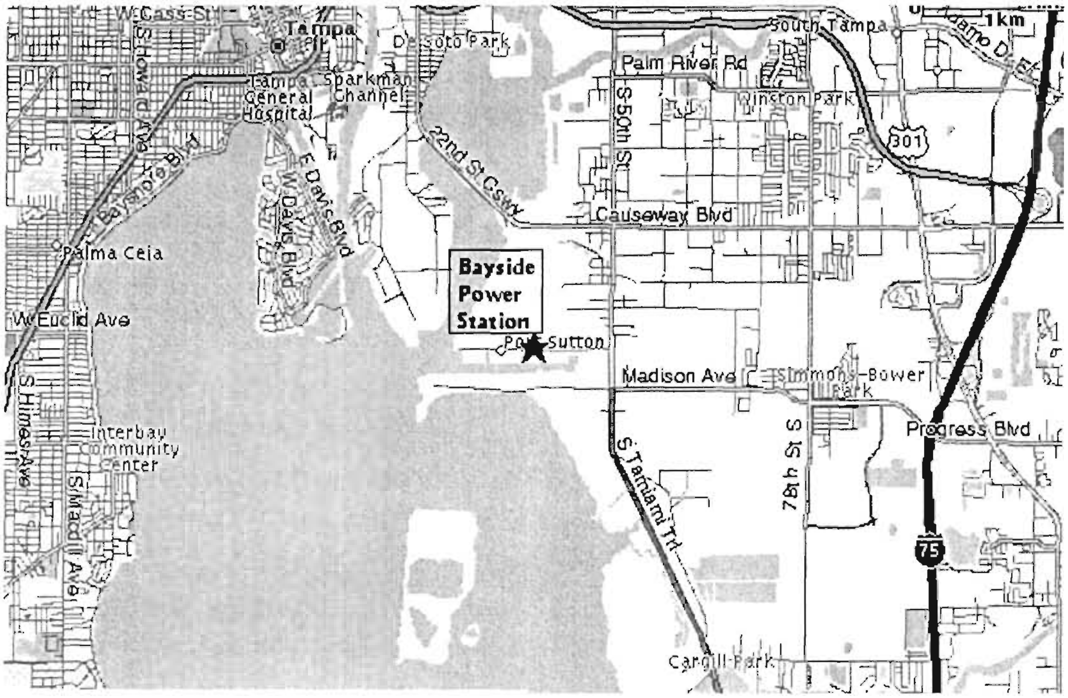
Authorized Representative:
Karen Sheffield, General Manager

Processing Schedule

- Issued Air Permit No. PSD-FL-301 on 03/30/01 for the Bayside Power Station (Units 1 and 2).
- Received application on 06/26/01 to add Units 3 and 4 to the Bayside Power Station.
- Received additional information on 07/17/01, 08/13/01, 09/11/01, 09/25/01, 10/01/01, and 10/30/01.

Facility Description and Location

The applicant, Tampa Electric Company, currently operates the F. J. Gannon Power Plant, which produces a nominal 1285 MW of electrical power primarily with coal-fired boilers. The applicant proposes to re-power the existing plant with eleven natural gas-fired combined cycle gas turbines, which will increase the nominal electrical generating capacity to 2845 MW. The primary Standard Industrial Classification (SIC) code for this facility is Industry No. 4911, Electric Services. The re-powered plant will be located within the existing plant boundaries on Port Sutton Road in Tampa, Florida. The UTM coordinates are: Zone 17, 360.00 km E, 3087.50 km N. The map coordinates are Latitude 27° 54' 18" and Longitude 82° 25' 21". The following map shows the approximate location of the plant.



Regulatory Categories

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). Based on the available information, this project does not trigger the requirements for a case-by-case 112(g) determination of the Maximum Available Control Technology (MACT).

Title IV: The new combined cycle gas turbines are subject to the Acid Rain provisions of the Clean Air Act.

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

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

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

NESHAP: No activities are identified as subject to a National Emissions Standard for Hazardous Air Pollutants (NESHAP).

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

2. PROPOSED PROJECT

Project Description

The applicant proposes to re-power the existing coal-fired F. J. Gannon Plant with eleven natural gas-fired combined cycle gas turbines. The re-powering project is required in accordance with the DEP/TEC Consent Final Judgment signed in December of 1999 and with the EPA/TEC Consent Decree signed in February of 2000. All existing coal-fired boilers (Gannon Units 1 – 6) will be shut down prior to January 1, 2005. The following describes the equipment and controls for the new Bayside Power Station.

Unit Description: Each combined cycle 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: Each gas turbine is paired with an individual HSRG. Individual combined cycle units are grouped to match the steam input capacity of the existing steam turbine electrical generators. The applicant identifies the groups of combined cycle gas turbines and steam turbines as "Bayside Units 1, 2, 3, and 4". The following table summarizes the electrical generating capacity for each combination of combined cycle gas turbines and steam-electrical turbines.

Table 2A. Summary of Generating Capacities

EU No.	Bayside Unit	MW, Shaft	Gannon ST	MW, ST	Total MW
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			
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	11 units	1859 MW	4 units	986	2845

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

Controls: The efficient combustion of natural gas at high temperatures minimizes the emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). Firing natural gas as the exclusive fuel minimizes emissions of sulfuric acid mist (SAM) and sulfur dioxide (SO_2) because natural gas contains only small amounts of sulfur. A selective catalytic reduction (SCR) system combined with dry low-NOx (DLN) combustion technology reduces emissions of nitrogen oxides (NOx).

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. The automated gas turbine control system also monitors fuel flow, heat input, power output, hours of operation, combustion reference temperatures, and other critical gas turbine control parameters.

Potential Emissions

The applicant estimates that the new gas turbines will result in the following potential annual emissions: 1383 tons per year of carbon monoxide; 1113 tons per year of nitrogen oxides, 1.4 tons per year of lead, 368 tons per year of particulate matter (front-half catch only), 89 tons per year of sulfuric acid mist, 487 tons per year sulfur dioxide, and 135 tons per year of volatile organic compounds. The shutdown of existing coal-fired units will result in large emissions decreases for many pollutants. PSD applicability is discussed later with the netting analysis.

3. 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 state rules and regulations of the Florida Administrative Code.

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

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

Federal Regulations

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

Citation	Description
40 CFR 51.166	Submittal of Implementation Plans – PSD
40 CFR 52.21	Approval of Implementation Plans – PSD
40 CFR 60	New Source Performance Standards (NSPS)
40 CFR 60	NSPS - Subpart A, General Provisions for NSPS Sources
40 CFR 60	NSPS - Subpart GG, Stationary Gas Turbines
40 CFR 60	NSPS - Applicable Appendices

40 CFR 72	Acid Rain - Permits Regulation
40 CFR 73	Acid Rain - Sulfur Dioxide Allowance System
40 CFR 75	Acid Rain - Continuous Emissions Monitoring
40 CFR 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
40 CFR 77	Acid Rain - Excess Emissions

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

Description of PSD Applicability Requirements

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

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

For new projects at 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. Project emissions exceeding these rates are considered "significant". For each significant pollutant, the applicant must employ the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analyses. 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.

Description of PSD Preconstruction Review Requirements

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

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

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

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

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

Netting Analysis

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

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

The revised application (09/11/01) identified the project as subject to PSD review for emissions of carbon monoxide, particulate matter, and volatile organic compounds. This was based on a netting analysis that considered the following:

- Emissions decreases from the shutdown of the coal-fired boilers for Gannon Units 3, 4, 5 and 6, and
- A netting analysis based on past actual emissions from the existing coal-fired Gannon Units as if "present-day BACT" were installed.

The Department and EPA entered into settlement agreements with the applicant intended to resolve alleged PSD violations. Therefore, it is appropriate that the past actual emissions from the existing coal-fired boilers reflect BACT-level controls that would otherwise have been required. This is consistent with the previous Bayside permitting action. The Department requested the applicant to base "present-day BACT" controls for a modified coal plant on the on the Department's most recent similar project, the Indiantown Cogeneration Limited Partnership coal-fired plant. The following table summarizes the controls and standards for this project.

Table 3A. Summary of "Present-Day" BACT Controls

Pollutant	Emission Rates			Control Efficiency	AP-42 (Range) Control Efficiency	Present-Day BACT Control Efficiency
	Past Actual [a]		Present Day BACT [b]			
	lb/ton coal	lb/mmBTU	lb/mmBTU	Percent (%)	Percent (%)	Percent (%)
CO	0.5	0.02	0.092, Good Combustion	NI	NA	NA
NOx	31.0	1.25	0.125, SCR	75 to 86%	90%	92%
Pb	4.2×10^{-04}	1.7×10^{-05}	1.6×10^{-05}, ESP/Baghouse	NI	6%	NA
PM/PM10	43.4	1.75	0.015, ESP/Baghouse	99 to 99.9%	99%	>99%
SAM [c]	2.85	0.11	0.0035, Lime Spray Dryer	NI	97%	95%
SO_2	57.0	2.30	0.142, Lime Spray Dryer	> 90%	94%	95%
VOC	0.04	0.002	0.003, Good Combustion	NI	NA	NA

Notes:

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

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

c. The applicant estimates a reduction of 35% in SAM emissions with a lime spray dryer. The Department estimates it would be at least 95%.

d. "NA" means not applicable. "NI" means no information.

Based on this information, the following table summarizes the revised netting analysis assuming that "present-day" BACT controls were installed on the re-powered Gannon Units during the representative two years of operation. It is primarily based on the applicant's submittal (09/11/01) with differences identified in the notes.

Table 3B. Summary of Netting Analysis

Pollutant	Gannon Units 3 - 6			Bayside Units 1 - 4	Net Emissions Change TPY	PSD SER* TPY	BACT Required? Yes/No
	Uncontrolled	Present Day BACT		Potential Emissions TPY			
	Past Actual TPY	Control Efficiency	Past Actual TPY				
CO [a]	**-609.3**	**0%**	**-609.3**	**1382.8**	**+773.5**	**100**	**Yes**
NOx	-33,921.3	92%	-2713.7	1113.0	-1600.7	40	No
Pb [b]	-12.2	84.5%	-1.9	1.4	-0.5	0.6	No
PM/PM10 [b]	**-1751.0**	**84.5%**	**-271.4**	**367.9**	**+96.5**	**25/15**	**Yes**
SAM [c]	-2461.7	95%	-123.1	89.4	-33.7	7	No
SO_2	-51,472.0	95%	-2573.6	486.5	-2087.1	40	No
VOC	**-78.1**	**0%**	**-78.1**	**134.9**	**+56.8**	**40**	**Yes**

Notes:

a. Past actual emissions are based on the annual operating reports for the representative two years and are shown as "negative" numbers to represent emissions decreases due to shutdown.

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

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

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

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

The Department also assumed that lead emissions would be reduced by a similar amount.

c. The applicant assumed a control efficiency of 35% from a lime spray dryer because of the low uncontrolled SAM emission levels. The Department assumed a control efficiency of 95% from a lime spray dryer similar to SO_2 control levels. Uncontrolled SAM emissions are based on actual SO_2 emissions and the ratio of SAM / SO_2 emission factors (AP-42).

According to the netting analysis, the Bayside re-powering project requires BACT determinations for emissions of CO, PM/PM_{10}, and VOC.

4. AVAILABLE INFORMATION

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

- Comments from EPA Region 4 and the Hillsborough EPC;
- DOE web site information on Advanced Turbine Systems Project;
- General Electric technical documents regarding DLN emissions and the gas turbine control system;
- Equipment cost quotes for a catalytic oxidation system to control CO and VOC emissions;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- U. S. Department of Energy Report (11/05/99) entitled, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" prepared by Onsite Sycom Energy Corporation;
- AP-42, Section 1.1 for coal-fired boilers (09/98);
- AP-42, Section 3.1 for gas turbines (04/00);
- EPA memorandums regarding gas turbines and MACT applicability dated 12/30/99 and 08/21/01;
- Annual Operating Reports for the Gannon Plant;
- Recently issued Department permits for the General Electric Model PG7241(FA) gas turbine;

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

Table 4A. Summary of Emissions Standards for 170 MW Combined Cycle Gas Turbines Firing Natural Gas

Project Location	Date	CT Model	Unit MW	Control Technologies	CO Limit ppmvd @ 15% O2	NOx Limit ppmvd @ 15% O2	PM Limit	SO2/SAM Limit	VOC Limit ppm
Hinds Energy, MS	01/00	GE 7FA	170	DLN/SCR	20	3.5	NI	LSF	NI
Attala Energy, MS	02/00	GE 7FA	170	DLN/SCR	20	3.5	NI	LSF	NI
Calpine Delta, CA (LAER)	02/00	GE 7FA or S/W 501FD	170	LPM/SCR	10, w/DB, 3-hr	2.5, w/DB	Fuel Specification	LSF	2
Calpine Bullhead City, AZ	02/00?	S/W 501FD	170	LPM/SCR	10, w/DB, 3-hr	3.0, w/DB	18.3 lb/hr	LSF	1.5
Calpine Blue Heron, FL	02/00	S/W 501FD	170	LPM/SCR	10, 24-hr	3.5, 3-hr	10% opacity	LSF	1.2
Mobile Energy, AL	03/00	GE 7FA	170	DLN/SCR	18, gas w/DB	3.5, w/DB	10% opacity	LSF	5
GPC Boat Rock, AL	04/00	GE 7FA	170	DLN/SCR	30, gas w/DB	3.5, w/DB	NI	LSF	8, w/DB
Calpine Osprey, FL	05/00	S/W 501FD	170	LPM/SCR	10, 24-hr	4.0, w/DB, 3-hr	10% opacity	LSF	2.3
Hines PB II, FL	01/01	S/W 501FD	170	LPM/SCR	16, 24-hr	3.5, 24-hr	10% opacity	LSF	2
CPV Gulfcoast, FL	02/01	GE 7FA	170	DLN/SCR	9, 3-hr	3.5, 3-hr	10% opacity	LSF	1.4
CPV Atlantic, FL	05/01	GE 7FA	170	DLN/SCR	9, 24-hr	3.5, 24-hr	10% opacity	LSF	1.4
CPV Pierce, FL	07/01	GE 7FA	170	DLN/SCR	9, 24-hr	2.5, 24-hr	10% opacity	LSF	1.4
Enron Ft. Pierce, FL	08/01	MHI 501F	170	LPM/SCR	3.5, 3-hr	3.5, 24-hr	10% opacity	LSF	2.2
El Paso Deerfield, FL	08/01	GE 7FA	170	DLN/SCR	7.4, 3-hr	2..5, 24-hr	10% opacity	LSF	1.4
TEC Bayside, FL	*Draft*	*GE 7FA*	*170*	*DLN/SCR*	*8, 24-hr*	*3.5, 24-hr*	*10% opacity*	*LSF*	*None, GCP*

Abbreviations:

Manufacturer

GE – General Electric
S/W – Siemens/Westinghouse
MHI – Mitsubishi Heavy Industries

Controls

DLN – Dry Low-NOx Combustion
GCP – Good Combustion Practices
LPM – Lean Premix Combustion
SCR - Selective Catalytic Reduction
WI = Water or Steam Injection
LSF – Low Sulfur Fuel

Other

LAER – Lowest Achievable Emission Rate
BACT – Best Available Control Technology
CEMS – Continuous Emissions Monitoring System

Notes: All data presented is for combined cycle gas turbines with a nominal shaft-driven electrical generating capacity of approximately 170 MW. Many of the limits presented are estimates based on assumptions made to present consistent units for comparison. "NI" means no information was available.

5. DRAFT BACT STANDARDS FOR CO AND VOC EMISSIONS

Discussion

Gas turbines emit carbon monoxide (CO) and volatile organic compounds (VOC) due to incomplete combustion of the fuels. For many combustion processes, CO emissions are inversely proportional to NOx emissions. However, the dry low-NOx combustor design for General Electric's Frame 7FA gas turbine has also successfully reduced CO emissions concurrently with NOx emissions. Because the controls used to lower CO emissions would also lower VOC emissions, the control technologies for these pollutants are reviewed together.

Applicant's Proposal

The applicant identified two control options that are technically feasible and commercially available for gas turbines: an efficient combustion design with good operating practices and a catalytic oxidation system. After attaining a lean premix steady-state operation, the dry low-NOx combustion design of the General Electric Model PG7241(FA) gas turbine results in low emissions of CO and VOC while also maintaining low NOx emissions. The Speedtronic™ automated gas turbine control system monitors and controls the gas turbine combustion process and operating parameters including, but not limited to, air/fuel distribution and staging, turbine speed, load conditions, temperatures, heat input, and fully automated startup/shutdown. The dry low-NOx combustion design and Speedtronic™ control system are integral to the Model PG7241(FA) gas turbine. "Good operating practices" means operating the unit in accordance with the manufacture's recommendations for efficient combustion, properly maintaining the gas turbine, and appropriate tuning of the combustors and controls system. No adverse energy, environmental, or economic impacts were identified with the use of an efficient combustion design and good operating practices.

A catalytic oxidation system consists of a noble metal catalyst section incorporated into the gas turbine exhaust. The catalyst promotes greater oxidation of CO (to carbon dioxide) and VOC (to carbon dioxide and water) at much lower temperatures (650°F to 1150°F) than would occur without a catalyst. Control efficiencies are primarily a function of the gas residence time, catalyst activity, and uncontrolled emission levels. CO control efficiencies can approach 90%. VOC control efficiencies would likely be in the 30% to 50% range due to the already low uncontrolled VOC emissions from the Model PG7241(FA) gas turbine, which are estimated to be less than 2.0 ppmvd corrected to 15% oxygen.

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

<u>Energy Impacts</u>: Installation of a catalytic oxidation system results in a pressure drop across the catalyst bed of approximately 1.2 inch of water column. This pressure drop causes backpressure on the gas turbine and reduces the power output from the unit (approximately a 0.24 percent energy penalty). The applicant estimates the lost power generation to be approximately $107,223 per year per gas turbine.

<u>Environmental Impacts</u>: Although the project proposes natural gas as the exclusive fuel, the catalytic oxidation system would oxidize small amounts of fuel sulfur to sulfuric acid mist. Also, due to the inherently low CO and VOC emissions from the Model PG7241(FA) gas turbine, the applicant believes 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.

<u>Economic Impacts</u>: The applicant estimates that the installation of a catalytic oxidation system would result in total capital investment of approximately $1,305,227 for one gas turbine with a total annualized cost of approximately $370,238 per year per gas turbine. Assuming 90% control efficiency, the catalytic oxidation system would remove in an additional 113.1 tons of CO per year per gas turbine resulting in a cost effectiveness of approximately $3300 per ton of CO removed. Assuming 50% control efficiency, the catalytic oxidation system would remove in an additional 6.1 tons of VOC per year per gas turbine resulting in a cost effectiveness of $60,400 per ton of VOC removed.

The applicant rejected the catalytic oxidation system as not cost effective for the project. In addition, the applicant did believe the additional controls would provide any measurable reductions in air quality impacts. The applicant proposed the following CO and VOC emissions standards for the combined cycle gas turbines based on the efficient combustion design of the Model PG7241(FA), the firing of natural gas as the exclusive fuel, and good operating practices.

- Requested CO Standard: 7.8 ppmvd corrected to 15% oxygen, 3-hour test average
- Requested VOC Standard: 1.3 ppmvd corrected to 15% oxygen, 3-hour test average

Draft BACT Determinations

The Department also recognizes the catalytic oxidation system as the top control alternative for CO and VOC emissions. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

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

Environmental Impacts: Although a catalytic oxidation system could result in increased sulfuric acid mist emissions, the oxidation process would also result in lower sulfur dioxide emissions. However, such increases and decreases would be minimal due to the extremely low fuel sulfur content of pipeline-quality natural gas. A catalytic oxidation system would reduce emissions of hazardous air pollutants, such as formaldehyde. However, uncontrolled HAP emissions from the entire project are estimated to be less than 10 tons per year. The Department rejects the applicant's argument that the further reduction of CO and VOC emissions would have negligible ambient impacts. The PSD preconstruction review process is specifically established for areas that are meeting the ambient air quality standards in order to prevent the deterioration of the current air quality. Actual ambient impacts from the project are evaluated in the modeling analysis and are not considered in making a determination of the Best Available Control Technology.

Economic Impacts: The Department does not endorse the applicant's estimate of the cost effectiveness for a catalytic oxidation system. However, it appears to be within the range of such estimates for other similar projects ($1500 to 4000 per ton). Even combining CO and VOC emission decreases results in a cost effectiveness of more than $3000 per ton of combined pollutants.

Due to the high combustion temperatures, efficient combustion design, and the firing of natural gas, emissions of CO, VOC, and even hazardous air pollutants (HAPs) such as formaldehyde are relatively low. Recent emissions performance tests at the Polk Power Station for the General Electric Model PG7241(FA) gas turbine indicate actual CO emission levels of less than 1 ppmvd when firing natural gas. Such low actual CO emissions would drive the cost effectiveness of a catalytic oxidation system even higher. The Department determines that add-on controls to further reduce CO and VOC emissions are unwarranted given the low emissions characteristics of this particular gas turbine and the exclusive firing of natural gas. Therefore, a catalytic oxidation system is rejected as not cost effective for this project. The Department recommends the following draft BACT standards.

- CO Draft BACT: 9.0 ppmvd corrected to 15% oxygen, based on a 24-hour block average of CEMS data
- VOC Draft BACT: Compliance with the CO standard represents a continuous indication of efficient combustion practices.

Compliance with the CO standard will be demonstrated by continuous emissions monitoring system (CEMS). Therefore, a slightly higher emission standard is specified. Uncontrolled VOC emissions are expected to be near detectable levels of the test method due to the efficient combustion design. Therefore, the compliance with the CO CEMS standard shall also serve as a continuous indication of efficient combustion practices to minimize emissions of volatile organic compounds.

6. DRAFT BACT STANDARDS FOR PM/PM_{10} EMISSIONS

Discussion

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

Requested Emissions Standards

At the estimated uncontrolled emission rates when firing pipeline-quality natural gas, the applicant states that installation of add-on controls such as baghouses or electrostatic precipitators would be cost prohibitive. In addition to firing natural gas as the exclusive fuel, the applicant proposed the following visible emissions limit as a work practice standard in lieu of a particulate matter emissions standard.

- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

Draft BACT Determinations

The Department agrees that further control of particulate matter emissions with add-on controls would be cost prohibitive for a gas turbine firing only natural gas. 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 standards.

- Pipeline-quality natural gas shall be the exclusive fuel for each combined cycle gas turbine.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

Compliance will be demonstrated by conducting at least annual opacity observations in accordance with EPA Method 9. Also, the CO CEMS standard will serve a continuous indication of efficient combustion practices to minimize emissions of particulate matter.

7. DRAFT STANDARDS FOR NOx EMISSIONS

Due to the high firing temperatures, nitrogen oxides (NOx) are the primary pollutant of concern from gas turbines. Although there are several available control alternatives, the DEP/TEC Consent Final Judgment requires the installation of a selective catalytic reduction (SCR) system on each combined cycle unit. SCR is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850° F, which is within the range of the exhaust from the heat recovery steam generators. SCR is a commercially available, demonstrated control technology currently employed on numerous combined cycle combustion turbine projects and is capable of very low NOx emissions with control efficiencies approaching 90%, depending primarily on the uncontrolled NOx emission rate. As previously discussed, the project nets out of PSD review for NOx emissions based on the emission rate specified in the DEP/TEC Consent Final Judgment.

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

During the original PSD permit application for the re-powering project, the Department worked closely with the applicant to develop appropriate cost estimates in accordance with the DEP/TEC Consent Final Judgment. The cost differential between the two control technologies was determined to be greater than $8 million and the installation of a SCONOx™ system was not required. Therefore, each combined cycle unit at the Bayside Power Station shall incorporate the dry low-NOx combustion design, the exclusive firing of natural gas, and an SCR system designed to minimize NOx and ammonia emissions. In accordance with the DEP/TEC Consent Final Judgment, the following is specified as the NOx emissions standard.

- NOx Standard: 3.5 ppmvd corrected to 15% oxygen based on a 24-hour block average

Compliance with the NOx standard will be demonstrated by continuous emissions monitoring system (CEMS). This level of control is generally within the range of recent BACT determinations for attainment areas. The above limit is much more stringent than the NSPS Subpart GG standard for gas turbines.

8. DRAFT STANDARDS FOR SAM/SO_2 EMISSIONS

Emissions of sulfur dioxide (SO_2) are generated from fuel sulfur in the natural gas. Small amounts of SO_2 may be converted to sulfuric acid mist (SAM) emissions. Natural gas is a clean fuel containing little ash, sulfur, or other contaminants. At the estimated uncontrolled emission rate when firing pipeline-quality natural gas, the installation of add-on flue gas desulfurization equipment is not reasonable. Again, the state and federal settlement agreements require re-powering with natural gas as the primary fuel. As previously discussed, the project nets out of PSD review for SAM and SO_2 emissions. In accordance with the DEP/TEC Consent Final Judgment, the following is specified as the SAM/SO_2 emissions standard.

- Pipeline-quality natural gas shall be the primary fuel for each combined cycle gas turbine.

The above fuel specification also represents the draft BACT standard for particulate matter emissions. It is a work practice standard that effectively limits potential emissions of SAM and SO_2 emissions, is typically considered BACT for gas turbine projects, and is clearly more stringent than the NSPS Subpart GG standard of 0.8% sulfur by weight for gas turbines.

9. DRAFT STANDARDS FOR AMMONIA SLIP EMISSIONS

Ammonia is injected into the exhaust gas stream as part of the selective catalytic reduction (SCR) system that is used to control NOx emissions. Some of the ammonia will escape past the catalyst without reaction, which is known as "ammonia slip". Ammonia emissions can be exhausted as ammonia or combine with sulfur to form fine particulate matter such as ammonium sulfates and bisulfates. Ammonia has been designated as an extremely hazardous substance under federal SARA Title III regulations and must be carefully managed to prevent accidental spills or nitrogen loading of the waters and soils. As part of the NOx control system, elevated levels of ammonia slip can indicate reduced catalyst effectiveness. Limiting ammonia slip can also minimize the formation of fine particulate matter, ammonium sulfates and ammonium bisulfates. Therefore, the following draft ammonia slip standards are specified.

- 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.
- If the tested ammonia slip rate exceeds 5 ppmvd corrected to 15% oxygen 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.

Compliance with the ammonia slip level shall be demonstrated at least annually in accordance with EPA's Conditional Test Method No. 27.

10. STARTUP, SHUTDOWN, MALFUNCTION, AND LOW LOAD OPERATION

Excess Emissions Prohibited

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

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 documented malfunction of a gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such incidents. As provided by the authority in Rule 62-210.700(5), F.A.C., these requirements are established in lieu of the provisions of Rule 62-210.700(1), F.A.C.

<u>Opacity During Startup and Shutdown</u>: 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.

<u>Low Load Operation</u>: Excluding startup, shutdown, and documented malfunction, each gas turbine is allowed up to 3 hours of operation below 50% base load in any 24-hour block, providing:

- The gas turbine is firing natural gas;
- The CO and NOx CEMS are functioning properly during such periods and recording valid emissions data within the span range of each monitor; and
- The gas turbine remains in compliance with the 24-hour block CO and NOx emissions standards based on valid CEMS data.

<u>CEMS Data Exclusion</u>: CO and NOx emissions data shall be recorded by the CEMS during 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 following requirements.

- Periods of data excluded for gas turbine startup (excluding steam turbine cold startup), shutdown, or documented malfunction shall not exceed four 1-hour emission averages in any 24-hour block due to all such episodes. Gas turbine startup is the commencement of operation of a gas turbine that has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, or pollution control device imbalances, which may result in elevated emissions. Shutdown is the process of bringing a gas turbine off line and ending fuel combustion. A malfunction is 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. A documented malfunction is a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.
- Periods of data excluded for a steam turbine cold startup shall not exceed sixteen 1-hour emission averages in any 24-hour block. A "steam turbine cold startup" is defined as 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. Based on actual operating data and experience, the Department may modify this period of data exclusion in the Title V air

operation permit without modifying this PSD permit.

- If the permittee provides at least five days advance notice prior to a major tuning session performed by the manufacturer's representative, monitoring data during tuning may be excluded from the 24-hour block compliance average. Periods of data excluded for such episodes shall not exceed a total of three 1-hour averages in any 24-hour block. Tuning sessions must be performed in accordance with the manufacturer's recommendations. {Permitting Note: As an example, a major tuning session would occur after a combustor change-out. A tuning session may take a few hours each day over a few days. No more than two major tuning sessions would be expected during any year.}

If a CEMS reports emissions in excess of a CO or NOx standard, the permittee shall notify the Compliance Authority within one (1) working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. [Rule 62-4.130, F.A.C.]

Startup and Shutdown Plan: A "steam turbine cold startup" is defined as 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 for each Bayside Unit shall be operated during such a startup. The permittee shall notify each Compliance Authority at least 24 hours in advance of a steam turbine cold startup. For each Bayside Unit, the permittee shall provide a Startup and Shutdown Plan as part of the application for a Title V air operation permit. The plan shall identify startup and shutdown procedures, duration of each procedure, and the methods used to minimize emissions during these periods. Within 90 days of completing eight steam turbine cold startups following commencement of commercial operation or within 90 days of completing 12 months of commercial operation (whichever occurs first), the permittee shall submit a revised plan to the Department based on actual operating data and experience. The Department shall review the actual operational data and determine whether period of data exclusion allowed by this permit for a steam turbine cold startup shall be modified to represent good operational practices. The Department shall also evaluate the operational information and determine whether a separate "warm startup" requirement shall be specified in the Title V operation permit for startup after the steam turbine has been offline for 24 hours or more, but less than 48 hours.

11. MACT 112(g) APPLICABILITY

EPA is required to promulgate Maximum Available Control Technology (MACT) standards for hazardous air pollutant (HAP) emissions from gas turbines. Because EPA has not yet proposed these standards, states are required to review new projects for the applicability of 112(g), which requires case-by-case MACT determinations if emissions are 10 tons per year or more of any single HAP or 25 tons per year or more of all combined HAPs. Therefore, the Department estimated HAP emissions from the proposed Bayside project based on the following information:

Letter from General Electric dated August 1, 2001: GE conducted formaldehyde emission testing on several GE Model 7241FA gas turbines with dry low-NOx combustors. Due to several problems with the test procedure, GE suggests an emissions factor of 1.3×10^{-04} lb/MMBtu when firing natural gas, which represents the highest average value when blank corrected.

EPA Memorandum dated August 21, 2001: EPA states that the original HAP emissions information (EPA memorandum dated 12/30/99) was based primarily on existing diffusion flame combustor technology. This technology results in higher emissions of CO, NOx, and HAPs than lean pre-mix combustor designs, such as General Electric's dry low-NOx combustion technology. Based on additional emissions performance testing, EPA states that the average formaldehyde emissions factor is 6.49×10^{-05} lb/MMBtu for larger gas turbines (10 MW to 170 MW) utilizing lean premix combustion. One theory for the much lower HAP emission levels is that, although the premixing of fuel and air with staged entry limits flame temperature and residence time at peak flame temperatures, it also reduces "cold spots" throughout the combustion zone providing more uniform destruction. EPA also states that, "For purposes of monitoring HAP performance of lean premix combustor turbines, NOx emission levels characteristic of lean premix combustor technology could be used as an indicator of proper lean premix combustor performance, which in turn would assure proper operation and low HAP emissions."

The AP-42 formaldehyde emission factor for gas turbines is 7.1 x 10^{-04} lb/MMBtu. Based on the new formaldehyde emissions factor of 6.49 x 10^{-5} lb/MMBtu, lean premix combustion technology offers a 90% reduction in formaldehyde emissions. Assuming similar reductions in other organic HAP emissions, the following table summarizes the potential HAP emissions from the Bayside project.

11A. Summary of Potential HAP Emissions form the Bayside Re-Powering Project

Hazardous Air Pollutant	AP-42 [a] Emission Factor lb/MMBtu	LPM [b] Emission Factor lb/MMBtu	Potential Emissions [c] Tons Per Year
1,3-Butadiene	4.30 x 10^{-07}	4.30 x 10^{-08}	0.00
Acetaldehyde	4.00 x 10^{-05}	4.00 x 10^{-06}	0.35
Acrolein	6.40 x 10^{-06}	6.40 x 10^{-07}	0.06
Benzene	1.20 x 10^{-05}	1.20 x 10^{-06}	0.11
Ethylbenzene	3.20 x 10^{-05}	3.20 x 10^{-06}	0.28
Formaldehyde	7.1 x 10^{-04}	6.49 x 10^{-05}	5.76
Napthalene	1.30 x 10^{-06}	1.30 x 10^{-07}	0.01
PAH	2.20 x 10^{-06}	2.20 x 10^{-07}	0.02
Propylene Oxide	2.90 x 10^{-05}	2.90 x 10^{-06}	0.26
Toluene	1.30 x 10^{-04}	1.30 x 10^{-05}	1.15
Xylene	6.40 x 10^{-05}	6.40 x 10^{-06}	0.57
Total HAPs	NA	NA	8.57

Notes:

a. Published AP-42 HAP emission factors in Section 3.1 for gas turbines dated April 2000.

b. The HAP emission factors for lean premix (LPM) combustion technology are based on the AP-42 emission factors and 90% reduction due to efficient, uniform combustion. The LPM formaldehyde emission factor is based on the EPA memorandum.

c. Annual potential emissions are based on eleven gas turbines firing natural gas at 1842 MMBtu per hour for 8760 hours per year.

Potential emissions are less than 10 tons per year for all individual HAPs and less than 25 tons per year for all combined HAPs. Based on this estimate, case-by-case 112(g) MACT does not apply to this project. Each gas turbine will continuously monitor CO and NOx emissions, which will ensure proper lean premix combustor performance and thereby low HAP emissions.

12. EXISTING COAL-FIRED UNITS

Shutdown of Gannon Units

The DEP/TEC Consent Final Judgment requires the shutdown of Gannon Units 1, 2, and 6 and the re-powering of Gannon Units 3, 4, and 5 to meet a NOx BACT limit of 3.5 ppm for combined cycle gas turbines. The EPA/TEC Consent Decree requires the re-powering of a combination of units totaling at least 550 MW. The applicant proposes to re-power of Gannon Units 3 through 6 with eleven combined cycle gas turbines and shutdown Gannon Units 1 and 2.

PSD applicability for this project is based on a netting analysis that considers emission decreases resulting from the shutdown of the existing coal-fired boiler for each re-powered Gannon Unit. Therefore, the permit will require shutdown of the existing coal-fired boiler prior to commencing operation of each corresponding Bayside Unit. This will not impose any hardship on the applicant because the existing units must be disconnected from the steam-electrical turbines during construction. The permit will also require the shutdown of all existing coal-fired Gannon Units before January 1, 2005.

Interim Coal Firing and Permanent Bar on Coal Combustion

The applicant did not predict any emissions increases for the remaining coal-fired boilers after the shutdown of each re-powered Gannon Unit. To prevent large increases in actual emissions from the remaining coal-fired units, the permit will reduce the limit on the total heat input through the coal yard after each re-powered Gannon Unit is shut down. Based on the representative 2-year "past actual" average coal firing rates for each unit and the average coal heat content, the reduced heat inputs are:

Table 13A. Reductions of Coal Yard Heat Input Limit

Shutdown Unit	Coal Usage Tons Per Year	Heating Value MMBtu per ton coal	Reduction of Limit mmBTU per year
Gannon Unit 3	453,054	20.0	$9.06 \times 10^{+06}$
Gannon Unit 4	435,187	20.0	$8.70 \times 10^{+06}$
Gannon Unit 5	549,023	24.0	$13.2 \times 10^{+06}$
Gannon Unit 6	890,562	24.0	$21.4 \times 10^{+06}$

The information presented above is based on the Annual Operating Reports submitted for the F. J. Gannon Power Plant. The current Title V operation permit limits the total heat input from the coal yard to $69.9 \times 10^{+06}$ MMBtu per year. After shutdown of the coal-fired boiler for each re-powered Gannon Unit, the limit on heat input from the coal yard shall be reduced by the actual annual heat input from the shutdown boiler as specified above. In accordance with the EPA/TEC Consent Decree, all six coal-fired boilers must be shutdown and cease operation before January 1, 2005. Shutdown means the permanent disabling of a coal-fired boiler such that it cannot burn any fuel (including "wood-derived" fuels) nor produce any steam for electricity production, other than through re-powering. In addition, the EPA/TEC Consent Decree prohibits TEC from combusting coal in the operation of any unit at Gannon plant commencing on January 1, 2005.

13. SUMMARY OF PROJECT EMISSIONS

The following table summarizes the actual annual emissions from the F. J. Gannon Power Plant and the potential annual emissions from the Bayside Power Station.

Table 13A. Comparison of Emissions After 2004

Pollutant	Gannon Units 1 – 6 Decreases Due to Shutdown Tons Per Year [a]	Bayside Units 1 – 4 Increases Due to New Units Tons Per Year [b]	Net Emissions Change Tons Per Year [c]
CO	- 748	+ 1383	+ 635
NOx	- 29,927	+ 1113	- 28,814
Pb	- 20	+ < 2	- 18
PM/PM10	- 1997	+ 578	- 1419
SAM	- 3056	+ 89	- 967
SO2	- 61,119	+ 487	- 60,632
VOC	- 114	+ 135	+ 21

Notes:

a. Actual annual emissions are based on the Annual Operating Reports for all emission units at the existing Gannon Plant.

b. Potential annual emissions are based on the permit limits and firing natural gas at the maximum permitted heat input rate for 8760 hours per year for each of the eleven gas turbines.

c. The net emissions change represents the difference between the current actual emission levels from the existing plant and the maximum permitted emissions from the proposed new plant after all coal-fired operations are shut down.

As shown, the project will result in large decreases in emissions of lead, nitrogen oxides, particulate matter, sulfuric acid mist, and sulfur dioxide. Based on potential emissions, the project results in increased emissions of carbon monoxide and volatile organic compounds. However, based on recent test data for the General Electric Model PG7241(FA) gas turbine, actual CO and VOC emissions will likely be less than half of the potential emissions, which would result in actual emission decreases for these pollutants as well.

14. AIR QUALITY IMPACT ANALYSIS

Executive Summary

In accordance with Rule 62-212.400(5)(d), F.A.C., an ambient impact analysis is required for projects subject to the PSD preconstruction review requirements. For each emission increase exceeding a PSD significant emissions rate defined in Table 62-212.400-2, F.A.C., the applicant must demonstrate that the project will not cause or contribute to a violation of any ambient air quality standard or maximum allowable ambient increase. Nitrogen dioxide (NO2), particulate matter (PM10), and sulfur dioxide (SO2) are criteria pollutants with defined ambient air quality standards (AAQS), PSD increments, Class I significant impact levels, and Class II significant impact levels. Carbon monoxide (CO) is a criteria pollutant with defined AAQS and PSD Class II significant impact levels. VOC is a precursor to the criteria pollutant ozone with a defined threshold of 100 tons per year, above which could trigger an ambient impact analysis.

As previously described, the proposed project will increase net emissions of CO and VOC in excess of PSD significant emission rates. Although the evaluation of Best Available Control Technology included PM_{10}, this was based on the revised netting analysis, which assumed "present-day" BACT controls were installed on existing Gannon Units 3 through 6. Actually, no such controls are in place and the Bayside project will result in net emissions decreases for PM_{10} as well as NO_2 and SO_2. Therefore, only an evaluation of the ambient impacts from the significant emissions of CO and VOC is required for this project. In addition, an analysis must be performed for the project impacts on soils, vegetation, and visibility as well as impacts to air quality related to growth resulting from the project.

The net VOC emissions increase from the Bayside project is 57 tons per year. This emission rate is greater than the PSD significant emission rate of 40 tons per year, but is less than the de minimis level of 100 tons per year listed in Table 212.400-3, F.A.C. Therefore, no ambient impact analysis was required for VOC emissions. Even if the project did result in a VOC emissions increase above the de minimis level, the Department typically determines that it is not feasible to use regional models that incorporate the complex chemical mechanisms for predicting ozone formation resulting from specific projects.

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

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

Analysis of Existing Air Quality

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

Table 14A. Maximum Air Quality Impacts Compared to the De Minimis Levels

Pollutant	Averaging Time	Maximum Predicted Impact	De Minimis Level	Greater Than De Minimis Impact?
CO	8-hour	175 $\mu g/m^3$	575 $\mu g/m^3$	No
VOC	Annual Emission Rate	57 TPY	100 TPY	No

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

Models and Meteorological Data Used in Significant Impact and AAQS Analyses

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

Meteorological data used in the ISCST3 model was obtained from the National Climatic Data Center (NCDC) and consisted of the concurrent 5-year period from 1992 through 1996. This NCDC station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. Surface data was from the St. Petersburg/Clearwater International Airport (SPG), Station ID 72211.

Upper air data was from Ruskin (RUS), Station 12842. The surface and mixing height data for each of the five years were processed using EPA's PCRAMMET meteorological preprocessing program to generate the meteorological data files in the format required by the ISCST3 dispersion model.

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

Significant Impact Analysis

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

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

Twelve scenarios were modeled for firing natural gas consisting of three load conditions and four compressor inlet temperatures. The following table shows the results of the significant impact analysis.

Table 14B. Maximum Air Quality Impacts Compared to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact? (Yes/No)
CO	8-hour	175	500	No
	1-hour	262	2,000	No

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

Requested Modeling Analysis

At the request of the Department, the applicant performed an ambient impact analysis for CO, NO_2, PM/PM_{10}, and SO_2 for comparison with the AAQS based on the ISCST3 air dispersion model and the 12 scenarios for firing natural gas. The following table summarizes the results based on the latest submittal.

Table 14C. Maximum Predicted Ambient Impacts from Bayside Project Alone

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Florida AAQS ($\mu g/m^3$)	Federal AAQS ($\mu g/m^3$)
CO	HSH, 1-hr	261	40,000	40,000
	HSH, 8-hr	175	10,000	10,000
NO_2	Annual	3	100	100
PM_{10}	HSH, 24-hr	59	150	150
	Annual	6	50	50
SO_2	HSH, 3-hr	91	1300	1300
	HSH, 24-hr	23	260	365
	Annual	2	60	80

The analysis indicates that the project, evaluated independently, will not cause a violation of the state or federal ambient air quality standards. The Department also required a PSD increment analysis for PM_{10}. The following table summarizes the results.

Table 14D. Summary of PM_{10} Class II Increment Analysis

Pollutant	Averaging Period	Maximum Project Impact ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)
PM_{10}	HSH, 24-hr	19	30
	Annual	1	17

A similar analysis was not required for SO_2 due to the very large net emissions decreases resulting from the project (more than 50,000 tons per year), which would expand increment.

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

Impact on Soils, Vegetation, And Wildlife

Very low emissions are expected from these natural gas-fueled combustion turbines in comparison with conventional power plants generating equal power. 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. These values, in-turn, are less than the carnon monoxide 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 the re-powering of an existing plant.

15. 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. Cleve Holladay is the project meteorologist responsible for reviewing and validating the air quality impact analysis. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at 850/488-0114 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

DRAFT

PERMITTEE:

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

Authorized Representative:
Ms. Karen Sheffield, General Manager

Project No. 0570040-015-AC
Air Permit No. PSD-FL-301A
Facility ID No. 0570040
SIC No. 4911
Expires: July 1, 2005

PROJECT AND LOCATION

This permit authorizes construction of eleven new combined cycle gas turbines with an approximate electrical production capacity of 2845 MW. The new units will be used to re-power the steam-electrical generators for Units 3, 4, 5, and 6 at the existing F. J. Gannon Station. The re-powered plant will be renamed the "Bayside Power Station". The project will be located within the existing plant boundaries on Tampa's Port Sutton Road in Hillsborough County, Florida. The UTM coordinates are: Zone 17, 360.00 km E, 3087.50 km N.

STATEMENT OF BASIS

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

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A	- Terminology
Appendix B	- Final 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

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

(Date)

PROJECT DESCRIPTION

Upon completion of construction and shutdown of all coal-fired units, the new Bayside Power Station will have an approximate electrical production capacity of 2845 MW based on the nominal capacities for 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.	Emission Unit Description
001	Gannon Unit 1 – existing coal fired boiler with 125 MW steam electrical generator
002	Gannon Unit 2 – existing coal fired boiler with 125 MW steam electrical generator
003	Gannon Unit 3 – existing coal fired boiler with 180 MW steam electrical generator
004	Gannon Unit 4 – existing coal fired boiler with 188 MW steam electrical generator
005	Gannon Unit 5 – existing coal fired boiler with 239 MW steam electrical generator
006	Gannon Unit 6 – existing coal fired boiler with 414 MW steam electrical generator
008	Gannon Station Coal Yard - Serves existing Gannon Units 1 – 6
020	Bayside Unit 1A – 169 MW combined cycle gas turbine fired with natural gas
021	Bayside Unit 1B – 169 MW combined cycle gas turbine fired with natural gas
022	Bayside Unit 1C – 169 MW combined cycle gas turbine fired with natural gas
023	Bayside Unit 2A – 169 MW combined cycle gas turbine fired with natural gas
024	Bayside Unit 2B – 169 MW combined cycle gas turbine fired with natural gas
025	Bayside Unit 2C – 169 MW combined cycle gas turbine fired with natural gas
026	Bayside Unit 2D – 169 MW combined cycle gas turbine fired with natural gas
027	Bayside Unit 3A - 169 MW combined cycle gas turbine fired with natural gas
028	Bayside Unit 3B - 169 MW combined cycle gas turbine fired with natural gas
029	Bayside Unit 4A – 169 MW combined cycle gas turbine fired with natural gas
030	Bayside Unit 4B – 169 MW combined cycle gas turbine fired with natural gas

Notes:

a. Gannon Unit 5 (EU 005) must be shutdown before operating Bayside Unit 1 (EUs 020, 021, and 022).

b. Gannon Unit 6 (EU 006) must be shutdown before operating Bayside Unit 2 (EU 023, 024, 025, and 026).

c. Gannon Unit 3 (EU 003) must be shutdown before operating Bayside Unit 3 (EU 027 and 028).

d. Gannon Unit 4 (EU 004) must be shutdown before operating Bayside Unit 4 (EU 029 and 030).

e. EUs 001, 002, 003, 004, 005, and 006 must be shut down before January 1, 2005. The Department expects that other coal-related activities will also cease operation shortly after the shutdown of the coal-fired boilers.

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). Based on the available information, this project does not trigger the requirements for a 112(g) case-by-case determination of the Maximum Available Control Technology (MACT).

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

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

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

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

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

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

RELEVANT DOCUMENTS

- DEP/TEC Consent Final Judgment signed on December 7, 1999.
- EPA/TEC Consent Decree entered on October 5, 2000.
- PSD permit application (Bayside Units 1 and 2) received on September 21, 2000 and all related correspondence.
- Original PSD air construction Permit No. PSD-FL-301 issued on March 30, 2001.
- PSD permit application (Bayside Units 3 and 4) received on June 26, 2001 and all related correspondence.

ADMINISTRATIVE REQUIREMENTS

1. Effective Date: The effective date of this permit is (DRAFT).

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

3. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Management Division of the Hillsborough County Environmental Protection Commission, 1410 North 21 Street, Tampa, FL 33605. The phone number is 813/272-5530 and the fax number is 813/272-5605. 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. The phone number is 813/744-6100 and the fax number is 813/744-6084.

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/TEC Consent Final Judgment or the EPA/TEC 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/TEC Consent Final Judgment or the EPA/TEC 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 may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 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 62-210.300(1) and 62-212.300(1)(a), 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 each Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

EMISSIONS AND CONTROLS

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

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

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

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

TESTING REQUIREMENTS

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

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

    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

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

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

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

19. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C.; 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 Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

RECORDS AND REPORTS

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

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

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

A. COMBINED CYCLE GAS TURBINES

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

Emissions Units 020 – 030: Combined Cycle Gas Turbines

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 Unit	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			
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	11 GTs	1859 MW	4 STs	986	2845

Note: 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. <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. 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. Schedule: Bayside Unit 1 is scheduled for completion in May of 2003 and Bayside Units 2, 3, and 4 are scheduled for completion in May of 2004. The permittee shall inform the Department of any substantial changes to the construction schedule. [Application; Rule 62-212.400(BACT), F.A.C.]
4. Combined Cycle Gas Turbines: The permittee is authorized to install, tune, operate and maintain eleven 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): The preliminary design of the HRSGs provides three levels of steam conditions when firing natural gas (high pressure, intermediate pressure, and low pressure). The permittee shall submit the final design data with the Title V application. [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/TEC Consent Final Judgment; EPA/TEC Consent Decree; Rule 62-4.070(3), F.A.C.]
9. Evaporative Inlet Air-Cooling System: Each gas turbine may have an evaporative cooling system designed to reduce the temperature of the inlet air to the gas turbine compressor. The reduced temperature provides a greater mass flow rate and increases power production with additional fuel combustion. The preliminary design is for a water distribution system with packed media blocks of corrugated layers of fibrous material.

Air passing over the system wicks moisture away from the media to create the cooling effect. The permittee shall submit the final design data with the Title V application. [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. 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. 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).

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

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 No. 22 in this section, each SCR system shall be designed and operated for an ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. [Rule 62-4.070(3), F.A.C.]

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

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

d. **Particulate Matter (PM/PM_{10})**: The exclusive firing of pipeline-quality natural gas combined with the efficient combustion design and operation of each gas turbine represent the Best Available Control Technology (BACT) requirements for particulate matter emissions. Compliance with carbon monoxide and visible emissions standards shall serve as continuous indicators of efficient combustion to minimize particulate matter emissions. No performance tests are required. {Permitting Note: Particulate matter emissions are expected to be less than 12 pounds per hour when firing natural gas as determined by EPA Methods 5, front-half catch only.} [Rule 62-212.400(BACT), F.A.C.]

e. **Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2)**: The 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 No. 17 of this section, this standard applies to all loads. [Rule 62-212.400(BACT), F.A.C.]

g. **Volatile Organic Compounds (VOC)**: The exclusive firing of pipeline-quality natural gas combined with the efficient combustion design and operation of each gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with carbon monoxide standards shall serve as a continuous indicator of efficient combustion to minimize VOC emissions. No performance tests are required. {Permitting Note: VOC emissions are expected to be less than 3 pounds per hour and 1.3 ppmvd corrected to 15% oxygen as determined by EPA Method 25A measured and reported as methane.} [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 documented malfunction of a gas turbine. 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, and documented malfunction, each gas turbine is allowed up to three hours of operation below 50% base load in any 24-hour block, providing: the gas turbine is firing natural gas; 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 based on 24-hour block averages of valid CEMS data.

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

(1) *Startup, Shutdown, and Malfunction*: Periods of data excluded for gas turbine startup (excluding steam turbine cold startup), shutdown, or documented malfunction shall not exceed four 1-hour emission averages in any 24-hour block due to all such episodes. Gas turbine startup is the commencement of operation of a gas turbine that has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, or pollution control device imbalances, which may result in elevated emissions. Shutdown is the process of bringing a gas turbine off line and ending fuel combustion. A malfunction is 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. A documented malfunction is a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

(2) *Steam Turbine Cold Startup*: Periods of data excluded for a steam turbine cold startup shall not exceed sixteen 1-hour emission averages in any 24-hour block. A "steam turbine cold startup" is defined as 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. Based on actual operating data and experience, the Department may modify this period of data exclusion in the Title V air operation permit without modifying this PSD permit.

(3) *Tuning*: If the permittee provides at least five days advance notice prior to a major tuning session performed by the manufacturer's representative, monitoring data during tuning may be excluded from the 24-hour block compliance averages. Periods of data excluded for such episodes shall not exceed a total of three 1-hour averages in any 24-hour block. Tuning sessions must be performed in accordance with the manufacturer's recommendations. {Permitting Note: As an example, a major tuning session would occur after a combustor change-out. A tuning session may take a few hours each day over a few days. No more than two major tuning sessions would be expected during any year.}

If a CEMS reports emissions in excess of a CO or NOx standard, 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 Department may request a written summary report of the incident.

d. **Startup and Shutdown Plan**: A "steam turbine cold startup" is defined as 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 for each Bayside Unit shall be operated during such a startup. The permittee shall notify each Compliance Authority at least 24 hours in advance of a steam turbine cold startup. For each Bayside Unit, the permittee shall provide a Startup and Shutdown Plan as part of the application for a Title V air operation permit. The plan shall identify startup and shutdown procedures, duration of each procedure, and the methods used to minimize emissions during these periods. Within 90 days of completing eight steam turbine cold startups following commencement of commercial operation or within 90 days after 12 months of commercial operation (whichever occurs first), the permittee shall submit a revised plan to the Department based on actual operating data and experience. The Department shall review the actual operational data and determine whether data exclusion allowed for a steam turbine cold startup defined in Condition 23 of this section shall be modified to represent good operational practices. The Department shall also evaluate the operational information and determine whether a separate "warm startup" requirement shall be specified in the Title V operation permit for startup after the steam turbine has been offline for 24 hours or more, but less than 48 hours.

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. [Design; Rules 62-210.700(5), 62-4.130, and Rule 62-212.400 (BACT), F.A.C.]

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 for 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 is 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 Department, 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.) 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 No. 17 of this section. All periods of data excluded due to startup, shutdown or malfunction shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited. Excluded emissions shall be summarized in the required semiannual report.

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

e. *CO and CO_2 Certification.* The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semi-annually to each Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall 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. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

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 Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

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

[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 combustion 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 combustion 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. A report covering operations from January through June shall be submitted by July 30^{th} of each year. A report covering operations from July through December shall be submitted by January 30^{th} 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. EXISTING GANNON UNITS

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

EU ID	Emission Unit Description
001	Gannon Unit 1 – existing coal fired boiler with 125 MW steam electrical generator
002	Gannon Unit 2 – existing coal fired boiler with 125 MW steam electrical generator
003	Gannon Unit 3 – existing coal fired boiler with 180 MW steam electrical generator
004	Gannon Unit 4 – existing coal fired boiler with 188 MW steam electrical generator
005	Gannon Unit 5 – existing coal fired boiler with 239 MW steam electrical generator
006	Gannon Unit 6 – existing coal fired boiler with 414 MW steam electrical generator
008	Gannon Station Coal Yard - Serves existing Gannon Units 1 – 6

SHUTDOWN REQUIREMENTS

1. Shutdown of Coal-Fired Gannon Units

   a. *Shutdown of Gannon Unit 3*: The Gannon Unit 3 (EU 003) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 3 gas turbine (EU 027 and EU 028). Upon first fire in any Bayside Unit 3 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 9.06 x 10^{+06} mmBTU per calendar year.

   b. *Shutdown of Gannon Unit 4*: The Gannon Unit 4 (EU 004) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 4 gas turbine (EU 029 and EU 030). Upon first fire in any Bayside Unit 4 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 8.70 x 10^{+06} mmBTU per calendar year.

   c. *Shutdown of Gannon Unit 5*: The Gannon Unit 5 (EU 005) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 1 gas turbine (EU 020 - EU 022). Upon first fire in any Bayside Unit 1 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 13.2 x 10^{+06} mmBTU per calendar year.

   d. *Shutdown of Gannon Unit 6*: The Gannon Unit 6 (EU 006) coal-fired boiler shall be shut down and rendered incapable of operation prior to first fire in any Bayside Unit 2 gas turbine (EU 023 - EU 026). Upon first fire in any Bayside Unit 2 gas turbine, the heat-input limit on the coal yard (EU 008) shall be reduced by 21.4 x 10^{+06} mmBTU per calendar year.

   e. *Shutdown of Gannon Units 1 - 6*: The permittee shall shutdown and cease any and all operation of coal-fired Gannon Units 1 through 6 (EU 001 - 006) no later than December 31, 2004. "Shutdown" shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel (including wood-derived fuel) nor produce any steam for electricity production, other than through re-powering as specified in this permit.

   [Rule 62-212.400(BACT), F.A.C.; EPA/TEC Consent Decree]

2. Permanent Bar on Combustion of Coal: Commencing on January 1, 2005, the permittee shall not combust coal in the operation of any unit at this plant. [EPA/TEC Consent Decree]

3. Notification: Before January 1, 2005, the permittee shall notify the Department of plans for the coal storage and handling facilities. Additional permits may be required. [Rule 62-210.300, F.A.C.]

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

TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

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

FORMATS FOR PERMIT REFERENCES AND RULE CITATIONS

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

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

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

Facility Identification (ID) Number:

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

New Permit Numbers:

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

Old Permit Numbers:

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

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Table B-1. Emissions Standards for Bayside Units 1 - 4
Eleven General Electric Model PG7241(FA) Combined Cycle Gas Turbines Firing Natural Gas

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

Notes:

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

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

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

FINAL BACT DETERMINATIONS

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

The project did result in significant net actual emissions increases of carbon monoxide (CO) and volatile organic compounds (VOC). Based on an interpretation by EPA Region 4, emissions of particulate matter (PM/PM_{10}) would also be significant if BACT-level controls had previously been installed on the existing Gannon Units. For CO, PM/PM_{10}, and VOC emissions, the Department determines that the efficient combustion of pipeline-quality natural gas and good operating practices represent BACT for the combined cycle units. In addition to the control requirements, the CO, PM/PM_{10}, and VOC emissions standards specified in the permit and summarized in Table B-1 represent the determination of Best Available Control Technology (BACT). A continuous monitoring system (CEMS) is required to demonstrate continuous compliance with the CO standards. The CO CEMS will also serve as a continuous indicator of efficient combustion to minimize PM and VOC emissions. The Department's detailed technical review and rationale for the determinations of Best Available Control Technology (BACT) are presented in Technical Evaluation and Preliminary Determination issued with the draft permit package.

Determination By:

(DRAFT)

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

Recommended By:

(DRAFT)

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

Approved By:

(DRAFT)

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

Table E-1. Summary of Mass Emission Rates Vs. Compressor Inlet Temperatures

Pollutant	Compressor Inlet Temperature	Mass Emission Rate lb/hour
CO	18° F	31.1
	35° F	30.0
	59° F	28.7
	72° F	27.8
	93° F	26.9
NOx	18° F	24.7
	35° F	23.8
	59° F	23.1
	72° F	22.6
	93° F	21.9
PM/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:

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

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 (Yes, for CO, PM/PM_{10}, and VOC);

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

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

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)
$N \leq 0.015$	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 at 15% oxygen. The emissions standards of this permit are much 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.

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

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

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

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

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

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

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

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

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

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

Department requirement: The owner or operator 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 pursuant to Department authority and is consistent with guidance from EPA Region 4.}

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

Department requirement: The permit species sulfur monitoring methods.

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

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

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.*

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:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 11/28/01

C. Signature
X Ron Tietbohl
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No
Ron Tietbohl

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 2935

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)

OFFICIAL USE

7000 2870 0000 7028 2935

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

Postmark Here

Sent To
Karen Sheffield
Street, Apt. No.; or PO Box No.
Port Sutton Road
City, State, ZIP+ 4
Tampa, FL 33619

PS Form 3800, May 2000 See Reverse for Instructions

TAMPA ELECTRIC

RECEIVED

SEP 25 2001

BUREAU OF AIR REGULATION

September 21, 2001

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. 7901 6445 6623

Re: Requests for Additional Information
Bayside Power Station (Gannon Repowering Project)

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received the Department's request for additional information regarding the particulate matter emission factors and stack parameters for F.J. Gannon Station, and the requested data is enclosed.

TEC appreciates the opportunity to provide the additional information contained in this correspondence. If you have any questions, please call Shannon Todd or me at (813) 641-5125.

Sincerely,

Karen Sheffield

Karen Sheffield
General Manager-Bayside Power Station
Tampa Electric Company

EP\gm\SKT275

Enclosure

c/enc: Mr. Jerry Kissel, FDEP - SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

Table 1. F.J. Gannon and Bayside Power Station Stack Parameters

Emission Source	Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/sec)	Velocity (m/sec)	Stack Area (ft^2)	Flow Rate (ft^3/min)
F. J. Gannon Station (1973)										
Unit 1	200.0	61.0	14.1	4.30	309.0	427.0	26.5	8.1	156.15	248,271
Unit 2	250.0	76.2	10.0	3.05	309.0	427.0	55.9	17.0	78.54	263,423
Unit 3	250.0	76.2	10.6	3.23	266.0	403.2	65.5	20.0	88.25	346,812
Unit 4	235.0	71.6	9.6	2.93	286.0	414.3	46.2	14.1	72.38	200,644
Unit 5	230.0	70.1	14.6	4.45	288.0	415.4	56.7	17.3	167.42	569,547
Unit 6	306.0	93.3	17.6	5.36	291.0	417.0	54.3	16.6	243.28	792,622
F. J. Gannon Station (1974)										
Unit 1	200.0	61.0	14.1	4.30	309.0	427.0	27.3	8.3	156.15	255,766
Unit 2	250.0	76.2	10.0	3.05	309.0	427.0	56.1	17.1	78.54	264,365
Unit 3	250.0	76.2	10.6	3.23	266.0	403.2	48.1	14.7	88.25	254,682
Unit 4	235.0	71.6	9.6	2.93	286.0	414.3	48.2	14.7	72.38	209,330
Unit 5	230.0	70.1	14.6	4.45	288.0	415.4	46.9	14.3	167.42	471,107
Unit 6	306.0	93.3	17.6	5.36	291.0	417.0	52.7	16.1	243.28	769,267
Bayside Station										
CT1A - CT4B	150.0	45.7	19.0	5.79	212.0	373.2	59.9	18.3	283.53	1,019,002
(Per CT @ 100% Load, 59°F)										

Sources: ECT, 2001.
TEC, 2001.

Table 2. F.J. Gannon and Bayside Power Station PM Emission Rates

Emission Source	1973 PM (lb/hr)	1973 PM (g/s)	1974 PM (lb/hr)	1974 PM (g/s)	1975 PM (lb/hr)	1975 PM (g/s)	1976 PM (lb/hr)	1976 PM (g/s)
F. J. Gannon Station								
Unit 1	190	23.9	206	26.0	204	25.7	191	24.1
Unit 2	220	27.7	107	13.5	99	12.5	214	27.0
Unit 3	330	41.6	248	31.2	313	39.4	32	4.0
Unit 4	464	58.5	568	71.6	56	7.1	84	10.6
Unit 5	840	105.8	669	84.3	677	85.2	42	5.3
Unit 6	2,170	273.4	44	5.5	38	4.8	51	6.4
Totals	4,214	531.0	1,842	232	1,387	175	614	77
Bayside Station (Future)								
CT1A - CT4B (Per CT @ 100% Load, 59°F)	20.3	2.6	N/A	N/A	N/A	N/A	N/A	N/A
Totals (11 CTs)	223.30	28.1	N/A	N/A	N/A	N/A	N/A	N/A

Notes:
1. F.J. Gannon Station PM emissions based on EPA Reference Method 17 (front half only).
2. Bayside PM emissions based on EPA Reference Methods 201 and 202 (front and back half).

Sources: ECT, 2001.
TEC, 2001.

TAMPA ELECTRIC

RECEIVED

SEP 10 2001

BUREAU OF AIR REGULATION

September 10, 2001

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. 7901 5518 4035

Re: Requests for Additional Information
Bayside Power Station (Gannon Repowering Project)

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your requests for additional information dated August 20, 2001 addressing the proposed repowering of F.J. Gannon Station to Bayside Power Station. The original requests were sent via email to Mr. Tom Davis of ECT. TEC has noted that within the two requests, there are a total of five additional questions or requests by the Florida Department of Environmental Protection (FDEP). For your convenience, TEC has restated each point and provided a response below each specific issue.

FDEP Issue 1
The application indicates the 1998 AP-42 emission factor as the reference for sulfuric acid mist emissions from the coal-fired units. What is the emission factor? Please note any assumptions.

TEC Response
The emission factor used for sulfuric acid mist for coal fired units varies depending on the sulfur content of the fuel. According to AP-42, in a coal fired unit, one can expect 0.7% of the fuel bound sulfur to be emitted as sulfur trioxide. As shown in Enclosure 1, this factor is used to calculate the sulfur trioxide formation resulting from coal combustion. Then, the stoichiometric relationship between sulfur trioxide, water and sulfuric acid mist is used to calculate the amount of sulfuric acid mist formed as a result of the reaction between sulfur trioxide and water. Finally, as mandated by the EPA Consent Decree, TEC calculated the emissions of sulfuric acid mist from Gannon Station had BACT level controls been applied to Units 3 through 6. These BACT level controls were assumed to be wet limestone flue gas desulfurization systems, which have the ability to remove approximately 35% of incoming sulfuric acid mist.

FDEP Issue 2
Cleve had sent a letter in July regarding the PSD increment for PM. I did not see the response for this item in your last submittal. Please let me know the status of this item.

TEC Response
TEC is currently performing the above referenced analysis, and will provide it to the Department upon completion.

FDEP Issue 3
Please submit the emission factors used to estimate past actual coal-firing emissions.

TEC Response
The requested emission factors are included as Enclosure 2.

FDEP Issue 4
Your most recent submittal indicates a net increase in VOC emissions of 21.5 TPY, which is below the 40 TPY PSD significant emission rate for VOC. However, based on TEC's annual operating reports, I estimate a 64.3 TPY increase. This makes the project subject to PSD for this pollutant, similar to the Bayside Units 1 and 2 project. Therefore, the Department will be making a BACT determination for VOC emissions. Please submit a proposal for BACT controls.

TEC Response
In our August 10, 2001 response to the Department's July 17, 2001 incompleteness letter TEC inadvertently used VOC emission factors applicable to cyclone fired boilers for all four Gannon boilers in the revised PSD netting analysis. Gannon Units 5 and 6 are Riley Stoker turbo, wet bottom fired units, and the VOC emission factor for these units differs from that used for Units 3 and 4. As such, the netting analysis has been adjusted to use the correct VOC emission factor for Gannon Units 5 and 6 as well as only natural gas firing for Bayside Units 1 and 2.

Based on the adjusted netting analysis, TEC calculates a net increase in VOC emissions of 56.8 tons per year. This differs from the values submitted by TEC in annual operating reports because the VOC emission factors for PC- fired, wet bottom boilers changed from 0.07 lb VOC/ton coal to 0.04 lb VOC/ton coal in 1998. TEC believes that it is appropriate to use the most recent emission factors for the purpose of performing this netting analysis.

Since this project results in a net increase of 56.8 tons of VOC emissions per year, TEC has enclosed a BACT analysis for VOC emissions (Enclosure 3). Based on this analysis, TEC has concluded that firing natural gas and good combustion practice is BACT for this project. This is consistent with other recently issued permits for similar facilities by FDEP.

FDEP Issue 5
There were discussions near the end of the last project indicating that TEC may not fire oil at all for this project. The current application for Bayside Units 3 and 4 indicates that these units will fire only natural gas. Please indicate whether or not Bayside Units 1 and 2 will fire distillate oil as a backup fuel.

TEC Response
Although the Bayside Units 1 and 2 were designed with provisions to fire distillate oil as a backup fuel, TEC is requesting to remove the oil firing permit conditions from the Bayside 1 and 2 Air Construction permit. Although these units have been designed to accommodate future oil firing, TEC has elected to fire natural gas as the only fuel. If the decision is made to fire distillate oil in Bayside Units 1 and 2 in the future, TEC will apply for a modification of the appropriate permits at that time.

TEC appreciates the opportunity to provide the additional information contained in this correspondence. If you have any questions, please call Shannon Todd or me at (813) 641-5125.

Sincerely,

Karen Sheffield

Karen Sheffield
General Manager-Bayside Power Station
Tampa Electric Company

EP\gm\SKT273

Enclosures

c: Mr. Jerry Kissel, FDEP - SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

Enclosure 1

TECO F.J. Gannon Station
Derivation of H_2SO_4 Emission Rates

Procedure References:

Coal: Per AP-42 (9/98), Section 1.1, Table 1.1-3, Footnote b, 0.7% of fuel sulfur is emitted as SO_3.

No. 2 Oil: Per AP-42 (9/98), Section 1.3, Table 1.3-1, boilers <100 MMBtu/hr (oil-firing), SO_3 emission factor is (2 x %S) lb SO_3 / 1,000 gallons oil.

Retroactive BACT control efficiency for H_2SO_4 = 35%

$SO_3 + H_2O = H_2SO_4$
(one mole of SO_3 and one mole of H_2O react to form one mole of H_2SO_4)

H_2SO_4 Calculation Equations:

Coal:
(lb S / 100 lb coal) x (ton coal / yr) x (2000 lb coal / ton coal) x (0.7 lb SO_3 / 100 lb S)
x (1 lb-mole H_2SO_4 / 1 lb-mole SO_3) x (lb-mole SO_3 /80 lb SO_3)
x (98 lb H_2SO_4 / lb-mole H_2SO_4) x (ton H_2SO_4 / 2000 lb H_2SO_4)
x (1 – (Retroactive BACT Control Efficiency / 100))

Oil:
(2 lb SO_3 / 1,000 gallon oil) x (% S oil) x (gallon oil / yr)
x (1 lb-mole H_2SO_4 / 1 lb-mole SO_3) x (lb-mole SO_3 /80 lb SO_3)
x (98 lb H_2SO_4 / lb-mole H_2SO_4) x (ton H_2SO_4 / 2000 lb H_2SO_4)
x (1 – (Retroactive BACT Control Efficiency / 100))

Example: 1996, Unit 3

Coal Usage: 298,202 ton/yr
Coal Sulfur Content: 1.12 weight percent sulfur
No. 2 Oil Usage: 311,000 gal/yr
No. 2 Oil Sulfur Content: 0.030 weight percent sulfur

Coal:
(1.12 lb S / 100 lb coal) x (298,202 ton coal / yr) x (2000 lb coal / ton coal)
x (0.7 lb SO_3 / 100 lb S) x (1 lb-mole H_2SO_4 / 1 lb-mole SO_3)
x (lb-mole SO_3 /80 lb SO_3) x (98 lb H_2SO_4 / lb-mole H_2SO_4)
x (ton H_2SO_4 / 2000 lb H_2SO_4) x (1 – (35 / 100))
= 18.62 ton/yr H_2SO_4

Oil:
(2 lb SO_3 / 1,000 gallon oil) x (0.030 S oil) x (311,000 gallon oil / yr)
x (1 lb-mole H_2SO_4 / 1 lb-mole SO_3) x (lb-mole SO_3 /80 lb SO_3)
x (98 lb H_2SO_4 / lb-mole H_2SO_4) x (ton H_2SO_4 / 2000 lb H_2SO_4)
x (1 – (35 / 100))
= 0.074 ton/yr H_2SO_4

Total = 18.62 (coal) + 0.074 (oil) = 18.69 ton/yr H_2SO_4

Enclosure 2

TECO F.J. Gannon Station
Derivation of Actual Coal-Firing Emission Rates

Procedure References:

Tampa Electric Company 1996 – 2000 Annual Operating Reports (AORs)

VOC Emission Factors:
Coal: Per AP-42 (9/98), Section 1.1, Table 1.1-19, TNMOC emission factor is 0.11 lb TNMOC / ton coal for cyclone furnaces (Units 3 & 4)
Coal: Per AP-42 (9/98), Section 1.1, Table 1.1-19, TNMOC emission factor is 0.04 lb TNMOC / ton coal for PC-fired, wet bottom furnaces (Units 5 & 6)
No. 2 Oil: Per AP-42 (9/98), Section 1.3, Table 1.3-3, Distillate fuel oil, NMTOC emission factor is 0.2 lb NMTOC / 1,000 gallons oil.

Retroactive BACT emission rate for NO_x = 0.10 lb NO_x / MMBtu

Retroactive BACT emission rate for PM/PM_{10} = 0.010 lb PM/PM_{10} / MMBtu

Retroactive BACT control efficiency SO_2 = 95.0 lb %

NO_x Calculation:

(Annual Heat Input [MMBtu/yr] From AOR) x (0.10 lb NO_x / MMBtu)

Example: 2000, Unit 5

Coal Usage: 418,667 ton/yr
Coal Heat Content: 24 MMBtu/ton
No. 2 Oil Usage: 101,569,000 gal/yr
No. 2 Oil Heat Content: 138,000 Btu/gal

Heat Input Coal:
(418,667 ton coal) x (24 MMBtu / ton coal)
= 10,048,008 MMBtu/yr

Heat Input Oil:
(10,156,900 gallon oil) x (138,000 Btu / gal) x (MMBtu / 1,000,000)
= 1,401,652 MMBtu/hr

Total Annual Heat Input = 10,048,008 (coal) + 1,401,652 (oil) = 11,449,660 MMBtu/yr

NO_x = (11,449,660 MMBtu/yr) x (0.10 lb NO_x / MMBtu) x (1 ton / 2,000 lb)

NO_x = 572.5 ton/yr

TECO F.J. Gannon Station
Derivation of Actual Coal-Firing Emission Rates

PM/PM_{10} Calculations:

(Annual Heat Input [MMBtu/yr] From AOR) x (0.010 lb NO_x / MMBtu)

Example: 1999, Unit 4

Coal Usage: 409,995 ton/yr
Coal Heat Content: 20 MMBtu/ton
No. 2 Oil Usage: 397,000 gal/yr
No. 2 Oil Heat Content: 138,000 Btu/gal

Heat Input Coal:
(409,995 ton coal) x (20 MMBtu / ton coal)
= 8,199,900 MMBtu/yr

Heat Input Oil:
(397,000 gallon oil) x (138,000 Btu / gal) x (MMBtu / 1,000,000)
= 54,786 MMBtu/hr

Total Annual Heat Input = 8,199,900 (coal) + 54,786 (oil) = 8,254,686 MMBtu/yr

PM/PM_{10} = (8,254,686 MMBtu/yr) x (0.010 lb NO_x / MMBtu) x (1 ton / 2,000 lb)

PM/PM_{10} = 41.2 ton/yr

SO_2 Calculation:

(Annual Emissions [ton/yr] From AOR) x (x (1 – (Retroactive BACT Control Efficiency / 100))

Example: 1996, Unit 3

Coal – SO_2: 6,400 ton/yr
Oil – SO_2: 6.5 ton/yr

SO_2 = (6,400 + 6.5 ton/yr SO_2) x (1 – (95 / 100))
SO_2 = (6,406.5 ton/yr SO_2) x (0.05)

SO_2 = 320.3 ton/yr

CO Calculation:

(Annual Emissions [ton/yr] From AOR)

Example: 1997, Unit 4

Coal – CO: 142 ton/yr
Oil – CO: 1 ton/yr

CO = (142 + 1 ton/yr CO)

CO = 143 ton/yr

VOC Calculation:

Coal:
(0.11 lb VOC / ton coal) x (ton coal / yr) x (ton VOC / 2000 lb VOC)

Oil:
(0.2 lb VOC / 1,000 gallon oil) x (gallon oil / yr) x (ton VOC / 2000 lb VOC)

Example: 1998, Unit 4

Coal Usage: 486,831 ton/yr
No. 2 Oil Usage: 598,990 gal/yr

Coal VOC = (486,831 ton/yr) x (0.11 lb VOC / ton coal) x (1 ton / 2,000 lb)
Coal VOC = 26.7 ton/yr

Oil VOC = (598,831 gallon oil/yr) x (0.2 lb VOC / 1,000 gallon oil) x (1 ton / 2,000 lb)
Oil VOC = 0.06 ton/yr

Total VOC = 26.7 (coal) + 0.06 (oil) = 26.8 ton/yr

Enclosure 3

REVISED PSD NETTING ANALYSIS
GANNON UNITS 3 – 6 / BAYSIDE UNITS 1 – 4
(ADJUSTED FOR RETROACTIVE BACT)

Table 3. Bayside Station Units 1, 2, 3 and 4
Netting Analysis - F.J. Gannnon Station Unit 5 Historical Emissions

Revised 8/23/01

	1996	1997	1998	1999	2000	96 - 00, 5 Yr Avg	98, 99 Avg
Coal Usage (tons)	574,584	450,802	556,487	541,559	418,667	508,420	549,023
Wt % Ash	7.47	8.26	8.15	7.58	6.95	7.68	7.87
Heat Content (10^6 Btu/ton)	24.65	23.96	24.00	24.00	24.00	24.12	24.00
Wt % S	1.19	1.16	1.21	1.17	1.22	1.19	1.19
Oil Usage (10^3 gal)	311.0	600.9	599.0	397.0	10,156.9	2,413.0	498.0
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.276
Wt % S	0.30	0.15	0.28	0.41	0.42	0.31	0.35
Total Heat Input (10^6 Btu/yr)	14,208,885	10,884,135	13,438,679	13,052,202	11,449,660	12,606,712	13,245,440
NO_x [(a)]	710.4	544.2	671.9	652.6	572.5	630.3	662.3
CO AOR	173.0	135.0	140.0	136.4	105.7	138.0	138.2
SO_2 [(b)]	648.4	537.7	685.1	630.1	538.6	608.0	657.6
H_2SO_4 [(c)] AP-42 (1998)	38.2	29.2	37.7	35.4	31.9	34.5	36.6
PM_{10} [(d)]	71.0	54.4	67.2	65.3	57.2	63.0	66.2
PM [(d)]	71.0	54.4	67.2	65.3	57.2	63.0	66.2
Pb AOR	3.8	3.0	3.7	3.6	0.1	2.8	3.4
VOC AP-42 (1998)	11.5	9.1	11.2	10.9	9.4	10.4	10.3

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Table 4. Bayside Station Units 1, 2, 3 and 4
Netting Analysis - F.J. Gannnon Station Unit 6 Historical Emissions

Revised 8/23/01

	1996	1997	1998	1999	2000	96 - 00, 5 Yr Avg	97, 98 Avg
Coal Usage (tons)	892,742	920,526	860,597	693,039	391,079	751,597	890,562
Wt % Ash	7.48	8.79	8.41	7.28	7.18	7.83	8.60
Heat Content (10^6 Btu/ton)	24.85	24.28	24.01	24.00	16.00	22.63	24.15
Wt % S	1.19	1.18	1.22	1.13	1.10	1.16	1.20
Oil Usage (10^3 gal)	311.0	639.9	599.0	362.0	6,587.5	1,699.9	619.4
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.270
Wt % S	0.30	0.15	0.28	0.41	0.42	0.31	0.22
Total Heat Input (10^6 Btu/yr)	22,229,515	22,438,664	20,745,925	16,682,892	7,166,339	17,852,667	21,592,294
NO_x [(a)]	1,111.5	1,121.9	1,037.3	834.1	358.3	892.6	1,079.6
CO AOR	269.0	278.0	216.0	174.2	98.5	207.1	247.0
SO_2 [(b)]	1,015.4	1,141.5	1,185.2	801.5	465.5	921.8	1,163.3
H_2SO_4 [(c)] AP-42 (1998)	59.3	60.6	58.7	43.8	26.2	49.7	59.6
PM_{10} [(d)]	111.1	112.2	103.7	83.4	35.8	89.3	108.0
PM [(d)]	111.1	112.2	103.7	83.4	35.8	89.3	108.0
Pb AOR	5.9	6.1	5.7	4.6	0.1	4.5	5.9
VOC AP-42 (1998)	17.9	18.5	17.3	13.9	8.5	15.2	17.9

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Table 5. Bayside Station

Bayside Units 1 - 4/F.J. Gannon Units 3 - 6 Emissions Netting Analysis

Revised 8/23/010

	F. J. Gannon Units 3, 4, 5 & 6 (tpy)					Units 3 & 4	Units 5 & 6	Units 3 - 6		Net	PSD	PSD
	1996	1997	1998	1999	2000	2 Yr [a] Avg	2 Yr [b][c] Avg	2 Yr [a][b][c] Avg	CT 1A-4B (tpy)	Change (tpy)	Threshold (tpy)	Review (Y/N)
Coal Usage (tons)	2,252,402	2,348,406	2,345,753	2,074,717	1,746,108	888,241	1,439,585	2,327,825	N/A	N/A	N/A	N/A
Wt % Ash	7.08	7.70	7.54	7.17	7.09	7.01	8.23	15.24	N/A	N/A	N/A	N/A
Heat Content (10^6 Btu/ton)	23.79	22.29	21.81	22.25	20.00	20.25	24.07	44.32	N/A	N/A	N/A	N/A
Wt % S	1.15	1.13	1.04	1.05	1.01	0.90	1.20	2.10	N/A	N/A	N/A	N/A
Oil Usage (10^3 gal)	1,244.0	2,457.5	2,396.0	1,553.0	37,058.2	10,553.9	1,117.4	11,671.3	N/A	N/A	N/A	N/A
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.000	138.273	276.273	N/A	N/A	N/A	N/A
Wt % S	0.30	0.15	0.28	0.41	0.42	0.41	0.28	0.69	N/A	N/A	N/A	N/A
Total Heat Input (10^6 Btu/yr)	54,357,901	53,475,548	52,585,549	47,078,210	40,146,544	19,436,830	34,837,734	54,274,565	N/A	N/A	N/A	N/A
NO_x [d]	2,717.9	2,673.8	2,629.3	2,353.9	2,007.3	971.8	1,741.9	2,713.7	1,113.0	-1,600.8	40.0	N
CO AOR	679.0	709.0	590.0	522.6	440.4	224.1	385.2	609.3	1,382.8	773.5	100.0	Y
SO_2 [e]	2,476.9	2,686.9	2,720.8	2,177.9	1,763.1	752.7	1,820.9	2,573.6	486.5	-2,087.1	40.0	N
H_2SO_4 [f] AP-42 (1998)	145.5	149.7	141.6	123.7	109.4	47.9	96.2	144.1	89.4	-54.7	7.0	N
PM_{10} [g]	271.8	267.4	262.9	235.4	200.7	97.2	174.2	271.4	978.1	706.7	15.0	Y
PM [g]	271.8	267.4	262.9	235.4	200.7	97.2	174.2	271.4	978.1	706.7	25.0	Y
Pb AOR	15.0	15.6	15.6	13.8	0.4	2.9	9.3	12.2	1.4	-10.9	0.6	N
VOC AP-42 (1998)	72.7	81.4	79.7	71.1	71.4	49.9	28.2	78.1	134.9	56.8	40.0	Y

(a) 1999, 2000 average for Units 3 and 4.
(b) 1998, 1999 average for Unit 5.
(c) 1997, 1998 average for Unit 6.
(d) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(e) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(f) Actual emissions reduced by 35% to reflect retroactive BACT.
(g) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

VOC BACT ANALYSIS
BAYSIDE UNITS 3 AND 4

4.0A BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS FOR VOLTILE ORGANIC COMPOUNDS

4.1A METHODOLOGY

The VOC BACT analysis was performed using the methodology previously described in Section 4.1 of the June 2001 Air Construction Permit Application.

4.2A 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 NSPS (40 CFR Part 60), NESHAP (40 CFR Parts 61 and 63), and 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 LHV of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV.
- Stationary gas turbines with a manufacturer's rated base load 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. The Bayside Units 3 and 4 CTs 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 VOC emission limitations.

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.

The Bayside Power Station 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 ozone Air Quality Maintenance Area. Sections 62-296.501 through 62-296.516, F.A.C., specify VOC emission standards for 16 categories of sources; none of these categories are applicable to CTs. In addition, these VOC emission standards are not applicable to modified VOC-emitting sources, such as Bayside Units 3 and 4, which will be subject to 40 CFR 52.21 (i.e., PSD NSR). Accordingly, there are no ozone Air Quality Maintenance Area VOC emission limits that are applicable to Bayside Units 3 and 4.

Section 62-204.800, F.A.C., adopts federal NSPS and NESHAP, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines* is applicable to the Bayside Unit 3 and 4 CTs. However, Subpart GG does not contain any VOC emission limitations. There are no applicable NESHAP requirements.

In summary, there are no federal or state VOC emission limitations applicable to Bayside Units 3 and 4.

4.3A <u>BACT ANALYSIS FOR VOC</u>

VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting 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 VOCs 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 VOC emissions. An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in VOC emission rates. Emissions of NO_x and VOC are inversely related; i.e., decreasing NO_x emissions will result in an increase in VOC emissions. Accordingly, combustion turbine vendors have had to consider the competing factors involved in NO_x and VOC formation in order to develop units that achieve acceptable emission levels for both pollutants.

4.3.1A POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling VOCs from gas turbines and duct burners: (1) combustion process design and (2) 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 CTs, approximately 99 percent, VOC emissions are inherently low. During normal operations, VOC exhaust concentrations from the Bayside Unit 3 and 4 GE 7FA CTs are projected to be only 1.3 parts per million by volume, dry (ppmvd), corrected to 15-percent oxygen (O_2).

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of VOCs to carbon dioxide (CO_2) and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for VOCs up to a temperature of approximately

1,100°F; further temperature increases will have little effect on control efficiency. Temperatures on the order of 900°F are needed to oxidize VOCs. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time which 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. 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 range using an oxidation catalyst control system is 30- to 50-percent. However, CTs with low uncontrolled VOC emission rates, such as the GE 7FA units, would be expected to have VOC control efficiencies on the low end of this range.

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 VOCs. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist.

Technical Feasibility

Both CT combustor design and oxidation catalyst control systems are considered to be technically feasible for Bayside Units 3 and 4. Information regarding energy, environmental, and economic impacts and proposed BACT limits for VOC are provided in the following sections.

4.3.2A 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 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 sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTs fired with natural gas.

Because VOC emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements; i.e., negligible reductions in ambient VOC/ozone levels. The location of Bayside Units 3 and 4 (Hillsborough County, Florida) is classified attainment for all criteria pollutants.

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 the Bayside Units 3 and 4 CTs is projected to have a pressure drop across the catalyst bed of approximately 1.2 inch of water (H_2O). This pressure drop will result in a 0.24 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 3,574,080 kilowatt-hours (kwh) (12,195 MMBtu) per year at base load (170-MW) operation and 100 percent capacity factor per CT. This energy penalty is equivalent to the use of 46.5 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 all four CTs. The lost power generation energy penalty, based on a power cost of $0.030/kwh, is $428,890 per year for all four CTs.

4.3.3A ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using the OAQPS factors previously summarized in Table 4-1 and project-specific economic factors provided in Table 4-2A. Specific capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 4-3A and 4-4A.

The base case Bayside Units 3 and 4 (i.e., for all four CT/HRSG units) annual VOC emission rate is 49.1 tpy. The controlled annual VOC emission rate, based on a 50 percent control efficiency, is 24.5 tpy. Base case and controlled VOC emission rates are summarized in Table 4-5A.

The cost effectiveness of oxidation catalyst for VOC emissions was determined to be $60,378 per ton of VOC removed. Based on the high control costs, use of oxidation catalyst technology to control VOC emissions is not considered to be economically feasible. Results of the oxidation catalyst economic analysis are summarized in Table 4-5A.

4.3.4A PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control VOCs from CTs is typically required only for facilities located in ozone nonattainment areas. BACT VOC limits obtained from the RBLC database for natural gas-fired CTs are provided in Table 4-6A. A summary of recent FDEP VOC BACT determinations for natural gas-fired combustion turbines is provided in Table 4-7A.

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 CTs fired with natural gas and low sulfur distillate fuel oil. Because VOC emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in only minor improvement in air quality, i.e., negligible reductions in ambient VOC/ozone levels.

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion are proposed as BACT for VOCs. These control techniques have been considered by FDEP to represent BACT for VOCs for all CT projects permitted

Table 4-2A. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0*
Control system life	Years	15
Oxidation catalyst life	Years	5
VOC control efficiency	%	50*
Electricity cost	$/kwh	0.030*
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance		22.00

* Per FDEP request.

Sources: ECT, 2001.
TEC, 2001.

Table 4-3A. Capital Costs for Oxidation Catalyst System, Four CTs

Item	Dollars		OAQPS Factor
Direct Costs			
Purchased equipment	2,680,000		A
Sales tax	160,800		0.06 x A
Freight	134,000		0.05 x A
Instrumentation	268,000		0.10 x A
Subtotal Purchased Equipment Cost	**3,242,800**		**B**
Installation			
Foundations and supports	259,424		0.08 x B
Handling and erection	453,992		0.14 x B
Electrical	129,712		0.04 x B
Piping	64,856		0.02 x B
Insulation for ductwork	32,428		0.01 x B
Painting	32,428		0.01 x B
Subtotal Installation Cost	**972,840**		
Subtotal Direct Costs	**4,215,640**		
Indirect Costs			
Engineering	324,280		0.10 x B
Construction and field expenses	162,140		0.05 x B
Contractor fees	324,280		0.10 x B
Startup	64,856		0.02 x B
Performance test	32,428		0.01 x B
Contingency	97,284		0.03 x B
Subtotal Indirect Costs	**1,005,268**		
TOTAL CAPITAL INVESTMENT	**5,220,908**	(TCI)	

Source: Engelhard, 2001.
ECT, 2001.

Table 4-4A. Annual Operating Costs for Oxidation Catalyst System, Four CTs

Item	Dollars		Basis
Direct Costs			
Catalyst costs			
Replacement (materials and labor)	2,668,224		
Credit for used catalyst	(360,000)		15% credit
Subtotal Catalyst Costs	2,308,224		
Annualized Catalyst Costs	**562,954**		5 yr @ 7.0%
Energy Penalties			
Turbine backpressure	428,890		0.24% penalty
Subtotal Direct Costs	**991,844**	(TDC)	
Indirect Costs			
Administrative charges	104,418		0.02 x TCI
Property taxes	52,209		0.01 x TCI
Insurance	52,209		0.01 x TCI
Capital recovery	280,271		15 yr @ 7.0%
Subtotal Indirect Costs	**489,107**		
TOTAL ANNUAL COST	**1,480,951**		

Sources: Engelhard, 2001.
ECT, 2001.
TEC, 2001.

Table 4-5A. Summary of VOC BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Rates (tpy)	Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
Oxidation catalyst	5.6	24.5	24.5	5,220,908	1,480,951	60,378	48,781	N	Y
Baseline	11.2	49.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Four GE PG7241 (FA) CTs, 100-percent load, natural gas-firing for 8,760 hr/yr.

Sources: ECT, 2001.
GE, 2001.
TEC, 2001.

Table 4-6A. RBLC VOC Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates		Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
			Issuance	Update					
AL-0128	ALABAMA POWER COMPANY - THEODORE COGEN	THEODORE	3/16/99	6/23/99	TURBINE, WITH DUCT BURNER	170.0 MW	0.016 LB/MMBTU	EFFICIENT COMBUSTION	BACT-PSD
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325.0 MMBTU/HR	8 LB/HR	NATURAL GAS AS PRIMARY FUEL	LAER
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, GAS, COMBINED CYCLE LM6000	421.4 MMBTU/H	1.1 LB/H	OXIDATION CATALYST	BACT
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, GAS, COMBINED CYCLE LM6000	421.4 MMBTU/H	1.1 LB/H	OXIDATION CATALYST	BACT
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, SIMPLE CYCLE LM6000 GAS	421.4 MMBTU/H	1.1 LB/H	OXIDATION CATALYST	BACT
CA-0813	SEPCO	RIO LINDA	10/5/94	8/31/99	TURBINE, GAS COMBINED CYCLE GE MODEL 7	920.0 MMBTU/H	3.7 LB/H	OXIDATION CATALYST	BACT
CA-0853	KERN FRONT LIMITED	BAKERSFIELD	11/4/86	8/5/99	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25.0 MW	3.12 LB/H	OXIDATION CATALYST. VOC IS SHOWN AS CH4	BACT-OTHER
CA-0855	CROCKETT COGENERATION - C&H SUGAR	CROCKETT	10/5/93	4/19/99	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(FA)	240.0 MW	352.6 LB/D	ENGELHARD OXIDATION CATALYST	BACT-OTHER
CA-0858	BEAR MOUNTAIN LIMITED	BAKERSFIELD	8/19/94	9/28/99	TURBINE, GE, COGENERATION, 48 MW	48.0 MW	0.6 PPMVD @ 15% O2	OXIDATION CATALYST	BACT-OTHER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246.0 MMBTU/H	16.7 LB/H		OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350.0 MMBTU/H	26.7 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385.0 MMBTU/H EACH TURBIN	35.2 T/YR		OTHER
CO-0024	PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	5/1/96	5/19/98	COMBINED CYCLE TURBINES (2), NATURAL	471.0 MW	1.4 PPMVD, SMPL CY	GOOD COMBUSTION CONTROL PRACTICES	BACT-PSD
CO-0039	FULTON COGENERATION ASSOC., L.P.	BRUSH	8/23/99	12/11/00	ELECTRIC GENERATION, TURBINES, NATURAL GAS	142.0 MW	3 PPMVD @ 15% O2	COMBUSTION CONTROLS	BACT-PSD
CT-0073	PRATT & WHITNEY, UTC	MIDDLETOWN	7/7/89	4/30/90	ENGINE, GAS TURBINE	238.0 MMBTU/H	0.014 LB/MMBTU		BACT-PSD
CT-0139	PDC EL PASO MILFORD LLC	MILFORD	4/16/99	6/17/99	TURBINE, COMBUSTION, ABB GT-24, #1	2.0 MMCF/H	3 LB/H NAT GAS	COMBUSTION CONTROLS	BACT
CT-0140	PDC EL PASO MILFORD LLC	MILFORD	4/16/99	6/17/99	TURBINE, COMBUSTION, ABB GT-24E #2	2.0 MMCF/H	3 LB/H NAT GAS	COMBUSTION CONTROLS	BACT
FL-0042	ORLANDO UTILITIES COMMISSION	TITUSVILLE	9/1/88	5/14/93	TURBINE, 2 EA	35.0 MW	7 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400.0 MW	9 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	33394	3/24/95	TURBINE, GAS, 4 EACH	400.0 MW	1.6 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWER	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240.0 MW	1 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35.0 MW	7 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	10 PPMVD	GOOD COMBUSTION	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1,214.0 MMBTU/H	6 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1,510.0 MMBTU/H	7 PPMVW	GOOD COMBUSTION PRACTICES	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1,032.0 MMBTU/H, NAT GAS	0.003 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116.0 MW	6 PPMVD	COMPLETE COMBUSTION	BACT-PSD
GA-0069	TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	12/18/98	6/23/99	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.0 MW EA	0.03 LB/MMBTU	VOC EMISSION IS BECAUSE OF NATURAL GAS.	BACT-PSD
GA-0069	TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	12/18/98	6/23/99	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.0 MW EA	0.0055 LB/MMBTU	VOC EMISSION IS BECAUSE OF NO.2 FUEL OIL.	BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338.0 MM BTU/HR TURBINE	3.6 LB/HR COMBINED	COMBUSTION CONTROLS, FUEL SELECTION	BACT
LA-0118	OCCIDENTAL CHEMICAL CORPORATION	HAHNVILLE	3/19/99	3/19/01	GAS TURBINES (3 UNITS)	170.0 MW	3 LB/H	DLN COMBINATION WITH OTHER TECHNOLOGIES.	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1,327.0 MMBTU/H	5.1 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH	BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528.0 MW TOTAL	0.4 PPM @ 15% O2		BACT-PSD
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175.0 MW	3 LB/H GAS		BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	7/13/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170.0 MW EACH	1 PPM	LOW NOX BURNER	BACT-PSD
MI-0245	SOUTHERN ENERGY, INC.	ZEELAND	3/16/00	8/22/00	COMBINED CYCLE TURBINE	9,000.0 GIGAJOULES	0.008 LB/MMBTU	PER CT. GOOD COMBUSTION PRACTICE	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1,313.0 MM BTU/HR	2 LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1,190.0 MMBTU/HR (EACH)	0.0046 LB/MMBTU	TURBINE DESIGN	OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617.0 MMBTU/HR (EACH)	4 PPMDV	TURBINE DESIGN.	BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11,257.0 HP	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100.0 MW	0 SEE P2	GOOD COMBUSTION PRACTICES	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100.0 MW	0		BACT-PSD
NY-0036	ONEIDA COGENERATION FACILITY	ONEIDA	2/26/90	5/18/90	TURBINE, GE FRAME 6	417.0 MMBTU/H	0.013 LB/MMBTU	COMBUSTION CONTROL	OTHER
NY-0038	EMPIRE ENERGY - NIAGARA COGENERATION CO.	LOCKPORT	5/2/89	5/18/90	TURBINE, GR FRAME 6, 3 EA	416.0 MMBTU/H	0.012 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
NY-0039	FULTON COGENERATION ASSOCIATES	FULTON	1/29/90	5/18/90	TURBINE, GE LM5000, GAS FIRED	500.0 MMBTU/H	5 LB/H	COMBUSTION CONTROL	BACT-PSD
NY-0040	JMC SELKIRK, INC.	SELKIRK	11/21/89	5/18/90	TURBINE, GE FRAME 7, GAS FIRED	80.0 MW	7 PPM	COMBUSTION CONTROL	BACT-PSD
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123.0 MMBTU/HR (EACH)	0.0045 LB/MMBTU	OXIDATION CATALYST	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON CRT HSE	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5,500.0 HP (EACH)	0.1 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS	OTHER
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6 KW EACH	105 PPM @ 15% O2	OXIDATION CATALYST	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360.0 MMBTU/HR	4.4 LB/HR	GOOD COMBUSTION PRACTICES	BACT-OTHER
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	1/12/99	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153.0 MW	4 PPM @ 15% O2	OXIDATION CATALYST WHEN FIRING NO. 2 OIL	LAER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5.0 MW	25 PPMV@15%O2	GOOD COMBUSTION	BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461.0 MW	5 PPMDV	COMBUSTION CONTROLS.	BACT-PSD
RI-0008	PAWTUCKET POWER	PAWTUCKET	1/30/89	3/31/91	TURBINE/DUCT BURNER	533.0 MMBTU/H	19 PPM @ 15% O2, GAS		BACT-PSD
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1,360.0 MMBTU/H EACH	5 PPM @ 15% O2		BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	33450	5/31/92	TURBINE, GAS, 2	49.0 MMBTU/H	0.016 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-OTHER
RI-0018	TIVERTON POWER ASSOCIATES	TIVERTON	2/13/98	2/8/99	COMBUSTION TURBINE, NATURAL GAS	265.0 MW	2 PPM @ 15% O2	GOOD COMBUSTION	BACT-PSD
SC-0031	BMW MANUFACTURING CORPORATION	GREER	1/7/94	8/12/96	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5 MM BTU/HR TURBINES	77.86 LBS/DAY		LAER
TN-0077	TN VALLEY AUTHORITY LAGOON CREEK COMBUS TURB	BROWNSVILLE	4/26/00	8/16/00	COMBUSTION TURBINE	194,400.0 MMBTU/H	1.4 PPM @ 15% O2	ANNUAL PRODUCTION LIMITS	BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	38 TPY	INTERNAL COMBUSTION CONTROLS	BACT
VA-0163	VIRGINIA POWER		9/7/89	4/30/90	TURBINE, GAS	1,308.0 MMBTU/H	2 LB/H/UNIT NAT GAS FI		BACT-PSD
VA-0177	DOSWELL LIMITED PARTNERSHIP		5/4/90	3/24/95	TURBINE, COMBUSTION	1,261.0 MMBTU/H	4.4 LB/H	COMBUSTOR DESIGN & OPERATION, GAS	OTHER
VA-0180	COMMONWEALTH GAS PIPELINE CORPORATION	GOOCHLAND	9/30/90	3/24/95	TURBINES, GAS FIRED, SINGLE CYCLE, 5	14.5 MMBTU/H EACH	0	EQUIPMENT DESIGN & OPERATION	BACT-PSD
VA-0184	BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	CHESTERFIELD	3/3/92	5/7/97	TURBINE, COMBUSTION	1,175.0 MMBTU/H NAT. GAS	2.3 LB/H/UNIT	FURNACE DESIGN	BACT-PSD
VA-0238	COMMONWEALTH CHESAPEAKE CORPORATION	NEW CHURCH	5/21/96	7/21/97	3 COMBUSTION TURBINES (OIL-FIRED)	6,000.0 HRS/YR	38.9 TPY	GOOD COMBUSTION OPERATING PRACTICES	BACT/NSPS

Source: RBLC 2001.

MAXIMUM	105.0 PPM @ 15% O2
MINIMUM	0.4 PPM @ 15% O2
MEDIAN	5.0 PPM @ 15% O2

Table 4-7A. Florida BACT VOC Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit (ppmvd @ 15% O_2)	Control Technology
03/07/95	Orange Cogeneration, L.P.	39	10.0	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	4.0	Good combustion
09/29/98	Florida Power Corporation Hines Energy Complex	165	7.0	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	1.4	Good combustion
12/04/98	Santa Rosa Energy, LLC	167	1.4	Good combustion
10/8/99	Tampa Electric Company – Polk Power Station	165	1.4	Good combustion
7/23/99	Seminole Electric Cooperative, Inc., Payne Creek	158	5.0	Good combustion
9/20/99	Lake Worth Generating	170	1.4	Good combustion
10/18/99	Vandolah Power Project	170	1.4	Good combustion
12/28/99	Osceola Power Project	170	3.7	Good combustion
1/13/00	Shady Hills Generating Station	170	1.4	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3	167	1.4	Good combustion
2/22/00	Reliant Energy Osceola	170	1.5	Good combustion
2/24/00	Gainesville Regional Utilities	83	1.4	Good combustion
7/31/00	Gulf Power – Smith Unit 3	170	4.0	Good combustion
2/6/01 (Draft)	Calpine Blue Heron	170	1.2	Good combustion
3/30/01	Tampa Electric Company – Bayside Units 1 & 2	170	1.3	Good combustion
7/5/01	Calpine Osprey	170	2.3	Good combustion
8/15/01	Ft. Pierce Re-Powering	180	2.2	Good combustion

Source: FDEP, 2001.

within the past 5 years. Maximum natural gas-firing VOC exhaust concentrations from the CT/HRSG units will be less than or equal to 1.3 ppmvd at 15 percent oxygen. This VOC exhaust concentration is consistent with recent FDEP VOC BACT determinations for CT/HRSG units; e.g., City of Tallahassee Purdom Unit 8 and Lakeland Utilities McIntosh Unit 5. VOC BACT emission limits proposed for Bayside Units 3 and 4 are provided in Table 4-8A.

Table 4-8A. Proposed VOC BACT Emission Limits

Emission Source	Proposed VOC BACT Emission Limits	
	ppmvd at 15 percent oxygen	lb/hr
GE PG7241 (FA) CT/HRSGs (Per CT/HRSG Unit)		
VOC (Natural Gas)	1.3	3.0

Sources: ECT, 2001.
TEC, 2001.

Adams, Patty

From: Koerner, Jeff
Sent: Monday, August 20, 2001 9:44 AM
To: Tom Davis (E-mail)
Cc: Shannon Todd (E-mail)
Subject: TEC Bayside - SAM Emission Factor, Coal-Fired Boilers

Tom,

1. The application indicates the 1998 AP-42 emission factor as the reference for sulfuric acid mist emissions from the coal-fired units. What is the emission factor? Please note any assumptions.

2. Cleve had sent a letter in July regarding the PSD increment for PM. I did not see the response for this item in your last submittal. Please let me know the status of this item.

Thanks!

Jeff Koerner
New Source Review Section
850/921-9536

Adams, Patty

From: Koerner, Jeff
Sent: Monday, August 20, 2001 11:05 AM
To: Tom Davis (E-mail)
Cc: Shannon Todd (E-mail)
Subject: TEC Bayside - Emission Factors, VOC Emissions and Oil Firing

Tom,

1. Please submit the emission factors used to estimate past actual coal-firing emissions.

2. Your most recent submittal indicates a net increase in VOC emissions of 21.5 TPY, which is below the 40 TPY PSD significant emission rate for VOC. However, based on TEC's annual operating reports, I estimate a 64.3 TPY increase. This makes the project subject to PSD for this pollutant, similar to the Bayside Units 1 and 2 project. Therefore, the Department will be making a BACT determination for VOC emissions. Please submit a proposal for BACT controls.

3. There were discussions near the end of the last project indicating that TEC may not fire oil at all for this project. The current application for Bayside Units 3 and 4 indicates that these units will fire only natural gas. Please indicate whether or not Bayside Units 1 and 2 will fire distillate oil as a backup fuel.

Thanks!

Jeff Koerner
New Source Review Section
850/921-9536

TECO

TAMPA ELECTRIC

RECEIVED
OCT 14 2002
BUREAU OF AIR REGULATION

October 11, 2002

Mr. Al Linero, P.E.
Acting Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7901 0888 6579

Re: Tampa Electric Company
Bayside Power Station
Project No. 0570040-015-AC
Air Permit No. PSD-FL-301A
Permitting Exemption

Dear Mr. Linero:

Tampa Electric Company (TEC) would like to courtesy notify the Florida Department of Environmental Protection (FDEP) that a temporary package boiler will be utilized on-site at Bayside Power Station. Bayside Unit 1 and 2 are under construction and the package boiler will be used to heat water for the cleaning of steam pipes and associated equipment in preparation for the startup of Bayside Unit 1 and 2. The package boiler will have a maximum of 600 horsepower. This is will have a maximum heat input capacity of 1.5 MMBtu per hour with a fuel usage of 70 gallons per hour of 0.5 percent sulfu, No.2 fuel oil. TEC believes that this package boiler is exempt from permitting under FDEP categorical exemption in the regulations 62-210.300(3)(a)1. F.A.C.

> " *One or more fossil fuel steam generators and hot water generating units located within a single facility; collectively having a total rated heat input equaling 100 million BTU per hour or less; and collectively burning annually no more than 145,000 gallons of fuel oil containing no more than 1.0 percent sulfur, or no more than 290,000 gallons of fuel oil containing no more than 0.5 percent sulfur, or an equivalent prorated amount of fuel oil if multiple fuels are used, provided none of the generators or hot water generating units is subject to the Federal Acid Rain Program or any standard or requirement under 42 U.S.C. section 7411 or 7412.*"

The package boiler will be brought on-site for Bayside Unit 1 in October and will remain on-site for a duration of approximately five (5) weeks. TEC requests FDEP confirmation of this exemption from permitting. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034.

Sincerely,

Dni Latchman for

Laura R. Crouch
Manager Air Programs
Environmental Affairs

Advised Ms. Latchman by phone that we disagree. She will submit exemption claim on different rule basis
aay 10/16

EA/bmr/DNL133

cc: Mr. Scott Sheplak (FDEP)
Mr. Sterlin Woodard (EPCHC)
Mr. Jerry Kissel (FDEP)

TAMPA ELECTRIC

RECEIVED

AUG 13 2001

BUREAU OF AIR REGULATION

August 10, 2001

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. 7901 2705 9498

Re: Request for Additional Information
Project No. 0570040-015-AC
Bayside Units 3 and 4 Re-powering Project

Dear Mr. Koerner:

Tampa Electric Company (TEC) has received your letter of incompleteness dated July 17, 2001 addressing the proposed repowering of F.J. Gannon Station Units 3 and 4 to Bayside Power Station Units 3 and 4. This correspondence is intended to provide a response to each specific issue raised by the Department. For your convenience, TEC has restated each point and provided a response below each specific issue.

FDEP Issue 1

In March of 2001, the Department issued a final permit for Bayside Units 1 and 2, which will re-power the steam turbines for existing Gannon Units 5 and 6. The application to re-power the steam turbines for existing Gannon Units 3 and 4 was submitted only three months later. The Department believes that this application is the second phase of the Gannon re-powering project. Please revise PSD netting analysis to include the following:

- Specify the PSD contemporaneous period as defined in Rule 62-212.400(2)(e)3, F.A.C.
- Include all emissions increases that have occurred or will occur during the contemporaneous period from all projects.
- Include all of the emissions decreases that have occurred or will occur during the contemporaneous period from all projects.
- Update the net emissions changes and PSD applicability accordingly.

TEC Response

The requested analysis is enclosed as attachment 1. Please note that Tampa Electric does not agree with the Department's position that the repowering of Gannon 3 and 4 is not a separate project from the repowering of Gannon 5 and 6.

FDEP Issue 2

Has TEC considered re-powering the existing steam turbines for Gannon Units 1 and 2? Has TEC contracted for any work involving the re-powering of these remaining steam turbines? Please submit a revised construction schedule for all units to be re-powered showing the planned startup date for each Bayside Unit and the shutdown date for each Gannon Unit.

TEC Response

At this time, TEC has no intention of repowering the existing steam turbines serving Gannon Units 1 and 2, nor has it contracted for any work involving the repowering of these two units. However, if TEC elects to repower these two steam turbines in the future, TEC will submit a permit application to the Department requesting permission to do so as outlined in Paragraph 27 of the EPA Consent Decree.

The proposed schedule for the repowering of the Gannon units 3-6 is provided below. This schedule is subject to change during the construction of the units. TEC will notify the Department of any significant deviation from this schedule.

Event	Estimated Date
Shutdown of Gannon 5	2/08/03
Startup of BPS 1	5/1/03*
Shutdown of Gannon 6	10/01/03
Startup of BPS 2	5/01/04*
Shutdown of Gannon 3	1/29/04
Startup of BPS 3	5/1/04*
Shutdown of Gannon 4	1/29/04
Startup of BPS 4	5/1/04*

***This is the expected date of commercial operation.**

FDEP Issue 3

Is TEC requesting any emissions standards, operational constraints, monitoring provisions, etc. that are different from those contained in the final permit issued for Bayside Units 1 and 2?

TEC Response

TEC is not requesting any emissions standards, operational constraints, monitoring provisions, etc. that are different from those contained in the final permit issued for Bayside Units 1 and 2.

FDEP Issue 4

Page 1-2 of the application states, "Following installation and commercial operation of Bayside Unit 3, existing coal fired operation at F.J. Gannon Station Unit 3 will permanently cease. Following installation and commercial operation of Bayside Unit 4, existing coal fired operation at F.J. Gannon Station Unit 4 will permanently cease." The Department notes that, for an emissions decrease to be enforceable, each existing unit must be completely shutdown and rendered incapable of operation prior to startup of the corresponding new unit. Please comment.

TEC Response

Page 1-2 of the application should read, "Prior to the commencement of commercial operation of Bayside Unit 3, existing coal fired operation at F.J. Gannon Station Unit 3 will permanently cease.

Prior to the commencement of commercial operation of Bayside Unit 4, existing coal fired operation at F.J. Gannon Station Unit 4 will permanently cease."

FDEP Issue 5

Each new "Bayside Unit" will consist of two combined cycle units described as:

> Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter and associated support equipment. The project also includes electric fuel heaters and cooling towers. Natural gas is the exclusive fuel.
>
> **Controls:** Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC are minimized by the efficient combustion of natural gas at high temperatures. NOx emissions are reduced by a Selective Catalytic Reduction (SCR) system combined with dry low-NOx (DLN) combustion technology when firing natural gas.
>
> **Heat Input:** At a compressor inlet air temperature of 59° F and firing 1842 mmBTU (HHV) per hour of natural gas, each unit produces approximately 169 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,020,000 acfm at 215° F.
>
> **Generating Capacity:** Bayside Units 3A and 3B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 3) with a nameplate rating of 180 MW. Bayside Units 4A and 4B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 4) with a nameplate rating of 188 MW of electrical power. Bayside Unit 3 is designed to produce a nominal 512 MW and Bayside Unit 4 is designed to produce a nominal 520 MW of electrical power. Is this an accurate description?

TEC Response

Based on the continued development and design of the Bayside Units 3 and 4 repowering project, some of the above description should be changed. Below is the suggested revised text, changed from the original using the strikethrough and underline convention.

Each new "Bayside Unit" will consist of two combined cycle units described as:

> **Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter and associated support equipment. The project also includes electric fuel heaters and cooling towers. Natural gas is the exclusive fuel.**
>
> **Controls: Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC are minimized by the efficient combustion of natural gas at high temperatures. NOx emissions are reduced by a Selective Catalytic Reduction (SCR) system combined with dry low-NOx (DLN) combustion technology when firing natural gas.**

<u>Heat Input</u>: At a compressor inlet air temperature of 59° F and firing 1659.5 mmBTU (LHV) per hour of natural gas, each unit produces approximately 169 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,030,163 acfm at 220° F.

<u>Generating Capacity</u>: Bayside Units 3A and 3B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 3) with a nameplate rating of 163 MW. Bayside Units 4A and 4B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 4) with a nameplate rating of 170 MW of electrical power. Bayside Unit 3 is designed to produce a nominal 497 MW and Bayside Unit 4 is designed to produce a nominal 488 MW of electrical power.

<u>FDEP Issue 6</u>
The Bayside 1 and 2 re-powering project combined with the Bayside 3 and 4 re-powering project will result in total formaldehyde emissions greater that 10 tons per year and total hazardous air pollutant emissions (HAP) greater that 25 tons per year. Please submit a case-by-case MACT analysis for the Department's review. The Department will make a case-by-case MACT determination for these phased projects.

<u>TEC Response</u>
General Electric has recently completed HAP emissions testing that suggests that actual HAP emissions are lower than those developed by EPA as part of the AP-42 emission factor inventory. In the Bayside Units 1 and 2 and the Bayside Units 3 and 4 permit applications, TEC used modified AP-42 emission factors to estimate the HAP emissions from the combustion turbines associated with each project. Based on the additional research completed by General Electric, it appears that HAP emissions will be lower than those originally submitted by TEC. Consequently, TEC requests that a formal MACT determination for Bayside Units 1 through 4 be deferred until the units commence commercial operation and TEC has an opportunity to perform HAP emissions testing. Specifically, Condition 2 of the Bayside Power Station Units 1 and 2 Air Construction Permit states:

"<u>MACT Determination</u>: The MACT applicability determination for this project is deferred until a combined cycle gas turbine is tested for HAP emissions in accordance with Condition No. 22 of this section. However, the permittee shall plan accordingly for the possibility of future applicable controls. If additional controls are later required, the Department shall allow the permittee a reasonable time to install equipment and conform to new or additional conditions. [Rules 62-4.080 and 62-204.800(10)(d), F.A.C.; Section 112(g), CAAA]"

TEC requests that this language be incorporated into the Bayside Units 3 and 4 Air Construction Permit.

<u>FDEP Issue 7</u>
Please provide a new vendor's quote for this project based on 11 proposed systems firing natural gas. Revise the cost analysis if necessary.

<u>TEC Response</u>
The requested information is provided as attachment 2. Based on the quotation obtained from Engelhard, it will cost $3,194 to remove one ton of carbon monoxide from each Bayside Unit. TEC believes that this cost exceeds that which has recently been considered to be economically feasible by the Department. It is also worth noting that this analysis is extremely conservative. Due to

combustion modifications completed on Gannon 5 and 6 to control NO_x emissions, actual CO emissions are likely much higher than those used as the baseline in this evaluation. As such, the actual increase in CO emissions due to this project is likely much lower than the 883.2 tons per year used in the netting calculations. This, in turn, drives up the cost to control one ton of CO.

<u>FDEP Issue 8</u>
The Department reserves the right to ask for additional information regarding the air quality analysis within the 30-day period after receiving the application with sufficient fee (on or before July 26, 2001).

<u>TEC Response</u>
TEC does not have any issues with the above statement.

<u>FDEP Issue 9</u>
The Department will forward any comments or questions if received from EPA Region 4, the National Park Service, the Hillsborough County Environmental Protection Commission, or the Department's Southwest District Office.

<u>TEC Response</u>
TEC appreciates the opportunity to comment on any questions raised by the above mentioned agencies.

TEC understands that with the submission of this additional information, the Department will continue processing the application.

If you have any questions regarding this matter, please Shannon Todd or me at (813) 641-5125.

Sincerely,

Karen Sheffield

Karen Sheffield
General Manager- Gannon Station
Tampa Electric Company

EP\gm\SKT270

Attachments

c: Mr. Jerry Kissel, FDEP - SWD
Mr. Jerry Campbell, EPCHC
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4
Ms. Katy Forney, EPA Region 4

Attachment 1

Bayside Units 1, 2, 3 and 4 PSD Netting Analysis

The procedures for determining applicability of the PSD NSR permitting program to modifications planned at existing major Florida facilities are specified in Rule 62-212.400(2)(d)4., F.A.C. Because the existing F.J. Gannon Station is a major facility (i.e., has potential emissions of 100 tpy or more of an air pollutant subject to regulation under Chapter 403, Florida Statutes) that would be subject to PSD preconstruction review if it were itself a proposed new facility (i.e., has potential emissions of 100 tpy or more of a pollutant regulated under the Clean Air Act and is located in an attainment area), modifications to the existing F.J. Gannon Station which result in a *significant net emissions increase* of any pollutant regulated under the Clean Air Act are subject to PSD NSR.

The term "significant net emission increase" is defined by Rule 62-212.400(2)(e), F.A.C. For each regulated pollutant, the net emission increase for a modification project is equal to the sum of the increases in emissions associated with the proposed project plus all facility-wide creditable, contemporaneous emission increases minus all facility-wide creditable, contemporaneous emission decreases. If this net emissions increase is equal to or greater than the applicable Table 212.400-2, F.A.C. Regulated Pollutants—Significant Emission Rates, then the net emission increase is considered to be "significant" and the modification will be subject to PSD NSR for that particular regulated pollutant.

In accordance with Rule 62-212.400(2)(e)3., F.A.C., the "contemporaneous" period for a modification project begins five years prior to the date of submittal of a complete permit application and ends when the new or modified emission units are estimated to begin operation.

In accordance with Rule 62-212.400(2)(e)4., F.A.C., contemporaneous emission increases and decreases are "creditable" if:

(1) the emission increase or decrease will affect PSD increment consumption; i.e., will consume or expand the available increment;

(2) The emission increase or decrease was not previously considered in the issuance of a PSD NSR permit (to avoid "double counting"); and

(3) The FDEP has not relied on the emission increase or decrease in attainment or reasonable further progress demonstrations.

Contemporaneous emission increases and decreases are based on *actual* emission rates. The term "actual emissions" is defined by Rule 62-210.200(12), F.A.C. For new emission units, including new electric utility steam generating units, actual emissions are equal to potential emissions. For changes to existing emission units, actual emissions are generally the actual average emission rates, in tpy, for the two year period preceding the change and which are representative of normal operations. The Department may allow the use of a different time period if it is determined that the other time period is more representative of the normal operation of an emissions unit.

For emission decreases, the old level of actual or allowable emissions (whichever is lower) must be greater than the new level of actual emissions. The actual emission decrease must also take place on or before the date that emissions from the modification project first occur and must be federally enforceable on and after the date the Department issues a construction permit for the modification project.

For Bayside Units 1, 2, 3 and 4, the contemporaneous period is projected to begin in September 1995 and end in June 2005. Creditable emission decreases that will occur within this contemporaneous period consist of the actual emissions associated with the cessation of coal-fired operations of F.J. Gannon Station Units 3, 4, 5 and 6. Creditable emission increases consist of those associated with Bayside Units 1, 2, 3 and 4. There are no other permanent creditable emission increases that have occurred or will occur at the F.J. Gannon Station during the September 1995 through June 2005 contemporaneous period.

Summaries of historical, actual emission rates for F.J. Gannon Station Units 1, 2, 3 and 4 for the 1996 – 2000 five year period are provided on Tables 1 through 4, respectively.

Table 5 provides an analysis of PSD NSR applicability for Bayside Units 1, 2, 3 and 4. Contemporaneous, creditable emission decreases were determined based on the average actual emissions for F.J. Gannon Station Units 3 and 4 for the 1999/2000 two-year period, F.J. Gannon Station Unit 5 for the 1998/1999 two-year period, and F.J. Gannon Station Unit 6 for the 1997/1998 two-year period. These actual emission rates reflect the retroactive application of NO_x, SO_2, and PM BACT in accordance with provisions of the EPA/TEC Consent Decree. The net emission rate changes due to the increase in potential emissions for Bayside Units 1, 2, 3 and 4, minus the two-year average actual emissions for F.J. Gannon Station Units 3, 4, 5 and 6 are all below the applicable Table 212.400-2, F.A.C. Regulated Pollutants—Significant Emission Rates with the exception of CO and PM/PM_{10}. For most regulated pollutants, there will be a substantial reduction in emissions; e.g., approximately 1,300 and 1,800 tpy for SO_2 and NO_x, respectively. Reductions in real actual emission rates (i.e., excluding adjustments for the retroactive application of NO_x, SO_2, and PM BACT) will be considerably higher. Accordingly, Bayside Units 1, 2, 3 and 4 are subject to PSD NSR for CO and PM/PM_{10} only.

Table 1. Bayside Station Units 1, 2, 3 and 4
Netting Analysis - F.J. Gannnon Station Unit 3 Historical Emissions

	1996	1997	1998	1999	2000	96-00, 5 Yr Avg	99,00 Avg
Coal Usage (tons)	298,202	502,172	441,838	431,164	474,944	429,664	453,054
Wt % Ash	6.60	6.88	6.79	6.87	7.09	6.85	6.98
Heat Content (10^6 Btu/ton)	23.31	20.06	19.19	21.00	20.00	20.71	20.50
Wt % S	1.12	1.15	0.87	0.95	0.85	0.99	0.90
Oil Usage (10^3 gal)	311.0	639.9	599.0	397.0	10,156.9	2,420.7	5,277
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.000
Wt % S	0.30	0.15	0.28	0.41	0.42	0.31	0.42
Total Heat Input (10^6 Btu/yr)	6,994,776	10,161,863	8,561,862	9,109,230	10,900,532	9,145,653	10,004,881
NO_x [(a)]	349.7	508.1	428.1	455.5	545.0	457.3	500.2
CO AOR	90.0	153.0	111.0	108.8	119.8	116.5	114.3
SO_2 [(b)]	320.3	488.6	372.9	372.9	367.5	384.4	370.2
H_2SO_4 [(c)] AP-42 (1998)	18.7	32.3	21.6	23.0	25.9	24.3	24.4
PM_{10} [(d)]	35.0	50.8	42.8	45.5	54.5	45.7	50.0
PM [(d)]	35.0	50.8	42.8	45.5	54.5	45.7	50.0
Pb AOR	2.0	3.3	2.9	2.9	0.1	2.2	1.5
VOC AP-42 (1998)	16.4	27.7	24.4	23.8	27.1	23.9	25.4

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Table 2. Bayside Station Units 1, 2, 3 and 4
Netting Analysis - F.J. Gannnon Station Unit 4 Historical Emissions

	1996	1997	1998	1999	2000	96-00, 5 Yr Avg	99,00 Avg
Coal Usage (tons)	486,874	474,906	486,831	408,955	461,418	463,797	435,187
Wt % Ash	6.75	6.85	6.79	6.95	7.13	6.89	7.04
Heat Content (10^6 Btu/ton)	22.35	20.87	20.04	20.00	20.00	20.65	20.00
Wt % S	1.08	1.04	0.87	0.94	0.86	0.96	0.90
Oil Usage (10^3 gal)	311.0	576.9	599.0	397.0	10,156.9	2,408.1	5,277
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.000
Wt % S	0.30	0.15	0.28	0.41	0.41	0.31	0.41
Total Heat Input (10^6 Btu/yr)	10,924,725	9,990,887	9,839,084	8,233,886	10,630,012	9,923,719	9,431,949
NO_x [(a)]	546.2	499.5	492.0	411.7	531.5	496.2	471.6
CO AOR	147.0	143.0	123.0	103.2	116.4	126.5	109.8
SO_2 [(b)]	492.8	519.2	477.7	373.5	391.6	450.9	382.5
H_2SO_4 [(c)] AP-42 (1998)	29.4	27.6	23.7	21.6	25.4	25.5	23.5
PM_{10} [(d)]	54.6	50.0	49.2	41.2	53.2	49.6	47.2
PM [(d)]	54.6	50.0	49.2	41.2	53.2	49.6	47.2
Pb AOR	3.2	3.2	3.2	2.7	0.1	2.5	1.4
VOC AP-42 (1998)	26.8	26.2	26.8	22.5	26.4	25.7	24.5

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Table 3. Bayside Station Units 1, 2, 3 and 4
Netting Analysis - F.J. Gannnon Station Unit 5 Historical Emissions

	1996	1997	1998	1999	2000	96 - 00, 5 Yr Avg	98, 99 Avg
Coal Usage (tons)	574,584	450,802	556,487	541,559	418,667	508,420	549,023
Wt % Ash	7.47	8.26	8.15	7.58	6.95	7.68	7.87
Heat Content (10^6 Btu/ton)	24.65	23.96	24.00	24.00	24.00	24.12	24.00
Wt % S	1.19	1.16	1.21	1.17	1.22	1.19	1.19
Oil Usage (10^3 gal)	311.0	600.9	599.0	397.0	10,156.9	2,413.0	498.0
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.276
Wt % S	0.30	0.15	0.28	0.41	0.42	0.31	0.35
Total Heat Input (10^6 Btu/yr)	14,208,885	10,884,135	13,438,679	13,052,202	11,449,660	12,606,712	13,245,440
NO_x [a]	710.4	544.2	671.9	652.6	572.5	630.3	662.3
CO AOR	173.0	135.0	140.0	136.4	105.7	138.0	138.2
SO_2 [b]	648.4	537.7	685.1	630.1	538.6	608.0	657.6
H_2SO_4 [c] AP-42 (1998)	38.2	29.2	37.7	35.4	31.9	34.5	36.6
PM_{10} [d]	71.0	54.4	67.2	65.3	57.2	63.0	66.2
PM [d]	71.0	54.4	67.2	65.3	57.2	63.0	66.2
Pb AOR	3.8	3.0	3.7	3.6	0.1	2.8	3.4
VOC AP-42 (1998)	31.6	24.9	30.7	29.8	24.0	28.2	28.2

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Table 4. Bayside Station Units 1, 2, 3 and 4
Netting Analysis - F.J. Gannnon Station Unit 6 Historical Emissions

	1996	1997	1998	1999	2000	96 - 00, 5 Yr Avg	97, 98 Avg
Coal Usage (tons)	892,742	920,526	860,597	693,039	391,079	751,597	890,562
Wt % Ash	7.48	8.79	8.41	7.28	7.18	7.83	8.60
Heat Content (10^6 Btu/ton)	24.85	24.28	24.01	24.00	16.00	22.63	24.15
Wt % S	1.19	1.18	1.22	1.13	1.10	1.16	1.20
Oil Usage (10^3 gal)	311.0	639.9	599.0	362.0	6,587.5	1,699.9	619.4
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.270
Wt % S	0.30	0.15	0.28	0.41	0.42	0.31	0.22
Total Heat Input (10^6 Btu/yr)	22,229,515	22,438,664	20,745,925	16,682,892	7,166,339	17,852,667	21,592,294
NO_x [(a)]	1,111.5	1,121.9	1,037.3	834.1	358.3	892.6	1,079.6
CO AOR	269.0	278.0	216.0	174.2	98.5	207.1	247.0
SO_2 [(b)]	1,015.4	1,141.5	1,185.2	801.5	465.5	921.8	1,163.3
H_2SO_4 [(c)] AP-42 (1998)	59.3	60.6	58.7	43.8	26.2	49.7	59.6
PM_{10} [(d)]	111.1	112.2	103.7	83.4	35.8	89.3	108.0
PM [(d)]	111.1	112.2	103.7	83.4	35.8	89.3	108.0
Pb AOR	5.9	6.1	5.7	4.6	0.1	4.5	5.9
VOC AP-42 (1998)	49.1	50.7	47.4	38.2	22.2	41.5	49.0

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Table 5. Bayside Station
Bayside Units 1 - 4/F.J. Gannon Units 3 - 6 Emissions Netting Analysis

	F. J. Gannon Units 3, 4, 5 & 6 (tpy)					Units 3 & 4	Units 5 & 6	Units 3 - 6		Net	PSD	PSD
	1996	1997	1998	1999	2000	2 Yr [a] Avg	2 Yr [b][c] Avg	2 Yr [a][b][c] Avg	CT 1A-4B (tpy)	Change (tpy)	Threshold (tpy)	Review (Y/N)
Coal Usage (tons)	2,252,402	2,348,406	2,345,753	2,074,717	1,746,108	888,241	1,439,585	2,327,825	N/A	N/A	N/A	N/A
Wt % Ash	7.08	7.70	7.54	7.17	7.09	7.01	8.23	15.24	N/A	N/A	N/A	N/A
Heat Content (10^6 Btu/ton)	23.79	22.29	21.81	22.25	20.00	20.25	24.07	44.32	N/A	N/A	N/A	N/A
Wt % S	1.15	1.13	1.04	1.05	1.01	0.90	1.20	2.10	N/A	N/A	N/A	N/A
Oil Usage (10^3 gal)	1,244.0	2,457.5	2,396.0	1,553.0	37,058.2	10,553.9	1,117.4	11,671.3	N/A	N/A	N/A	N/A
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.000	138.273	276.273	N/A	N/A	N/A	N/A
Wt % S	0.30	0.15	0.28	0.41	0.42	0.41	0.28	0.69	N/A	N/A	N/A	N/A
Total Heat Input (10^6 Btu/yr)	54,357,901	53,475,548	52,585,549	47,078,210	40,146,544	19,436,830	34,837,734	54,274,565	N/A	N/A	N/A	N/A
NO_x [d]	2,717.9	2,673.8	2,629.3	2,353.9	2,007.3	971.8	1,741.9	2,713.7	1,422.9	-1,290.8	40.0	N
CO AOR	679.0	709.0	590.0	522.6	440.4	224.1	385.2	609.3	1,492.5	883.2	100.0	Y
SO_2 [e]	2,476.9	2,686.9	2,720.8	2,177.9	1,763.1	752.7	1,820.9	2,573.6	757.1	-1,816.5	40.0	N
H_2SO_4 [f] AP-42 (1998)	145.5	149.7	141.6	123.7	109.4	47.9	96.2	144.1	129.9	-14.2	7.0	N
PM_{10} [g]	271.8	267.4	262.9	235.4	200.7	97.2	174.2	271.4	1,077.1	805.7	15.0	Y
PM [g]	271.8	267.4	262.9	235.4	200.7	97.2	174.2	271.4	1,077.1	805.7	25.0	Y
Pb AOR	15.0	15.6	15.6	13.8	0.4	2.9	9.3	12.2	1.6	-10.6	0.6	N
VOC AP-42 (1998)	124.0	129.4	129.3	114.3	99.7	49.9	77.3	127.2	148.7	21.5	40.0	N

(a) 1999, 2000 average for Units 3 and 4.
(b) 1998, 1999 average for Unit 5.
(c) 1997, 1998 average for Unit 6.
(d) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(e) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(f) Actual emissions reduced by 35% to reflect retroactive BACT.
(g) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Attachment 2

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830

ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail fred.booth@engelhard.com

DATE:	August 1, 2001	NO. PAGES	3
TO:	ECT	via e-mail	
ATTN:	Tom Davis		
	ENGELHARD		
ATTN:	Nancy Ellison		
FROM:	Fred Booth	Ph 410-569-0297 // FAX 410-569-1841	

RE: **TECO - Gannon**
CO Oxidation System Components
Engelhard Budgetary Proposal EPB00385

We provide Engelhard Proposal EPB00385 for Engelhard **Camet®** metal substrate CO oxidation system per your e-mail request of July 31, 2001.

Our Proposal is based on:

- Given data for GE 7FA Gas Turbine operating in unfired combined cycle mode;
- CO Catalyst for 90% CO Reduction;
- Advise VOC reduction - inlet levels not provided. VOC Composition assumed Non-Methane / Non-Ethane – 50% Saturated.
- Assumed HRSG inside liner dimensions of 67 ft H x 26 ft W.
- Three (3) Year Performance Guarantee;

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

ENGELHARD

ECT
TECO - Gannon
CO Oxidation System Components
Engelhard Budgetary Proposal EPB00385
August 1, 2001

ENGELHARD CORPORATION
CAMET® CO OXIDATION SYSTEMS

Scope of Supply: The equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

- Engelhard **CAMET®** CO Oxidation Catalyst Modules;
- Internal support structures for catalyst modules (frame). Frame design allows adding one more layer.
- Technical Service during installation and Start-Up;

Excluded from Scope of Supply:
Any internally insulated reactor ductwork to house catalysts
Any transitions to and from reactor
Any monorails and hoists for handling modules
Electrical grounding equipment
Foundations
All other items not specifically listed in Scope of Supply
Structural support
Any interconnecting field piping or wiring
Utilities
All Monitors

PRICES: fob, plant gate, job site **See Below**

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Three (3) years of operation or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life

DOCUMENT / MATERIAL DELIVERY SCHEDULE
Drawings / Documentation – 2-3 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details
Material Delivery

CO Modules	20 - 24 weeks after approval and release for fabrication

CO SYSTEM DESIGN BASIS:

Gas Flow from:	GE 7FA Combustion Turbine - Combined Cycle – NO duct burner
Gas Flow:	Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data
Temperature (At catalyst face):	See Performance data
CO Concentration (At catalyst face):	See Performance Data
CO Reduction:	90% CO Reduction
CO Pressure Drop:	See Performance data
VOC Concentration (At catalyst face):	Not Provided
VOC Reduction:	Advise
VOC Composition	Assumed Non-Methane / Non-Ethane – 50% Saturated

ENGELHARD

ECT
TECO - Gannon
CO Oxidation System Components
Engelhard Budgetary Proposal EPB00385
August 1, 2001

Performance Data and Budget Pricing

GIVEN / CALCULATED DATA	CASE	1	2
	AMBIENT	18	93
	FUEL	NG	NG
	TURBINE EXHAUST FLOW, lb/hr	3,811,000	2,302,000
	TURBINE EXHAUST GAS ANALYSIS, % VOL. - N_2	75.09	73.45
	O_2	12.52	12.79
	CO_2	3.88	3.53
	H_2O	7.71	9.36
	Ar	0.80	0.87
	GIVEN TURBINE CO, ppmvd @ 15% O_2	7.2	7.8
	GIVEN TURBINE CO, lb/hr	31.0	18.6
	GIVEN TURBINE VOC, ppmvd @ 15% O_2	N / A	N / A
	GIVEN TURBINE VOC, lb/hr	N / A	N / A
	CALC. GAS MOL. WT.	28.46	28.26
	ASSUMED GAS TEMP. @ CO CATALYST, °F (+/-25)	650	600
DESIGN REQUIREMENTS	CO OUT, ppmvd @ 15% O_2	0.72	0.78
	VOC OUT, ppmvd @ 15% O_2	Advise	Advise
	CO PRESSURE DROP - "WG MAX.	Advise	Advise
	GUARANTEED PERFORMANCE DATA		
	CO CONVERSION, % - Min.	90.0%	90.0%
	CO OUT, lb/hr - Max.	3.1	1.9
	CO OUT, ppmvd @ 15% O_2	0.7	0.8
	SO_2 -> SO_3 CONVERSION, % - Max.	10%	7%
	VOC** CONVERSION, % - Min.	42%	44%
	VOC** OUT, lb/hr	N / A	N / A
	VOC** OUT, ppmvd @ 15% O_2	N / A	N / A
	** VOC - NON-METHANE / NON-ETHANE – 50% SATURATED		
	CO PRESSURE DROP, "WG - Max.	1.2	0.6

CO SYSTEM - $$	**$670,000**
REPLACEMENT CO CATALYST MODULES - $$	**$600,000**

Dimensions:

Inside Liner Width	**(A) 26 ft**
Inside Liner Height	**(B) 67 ft**
Frame Depth	**(C) 18 in**

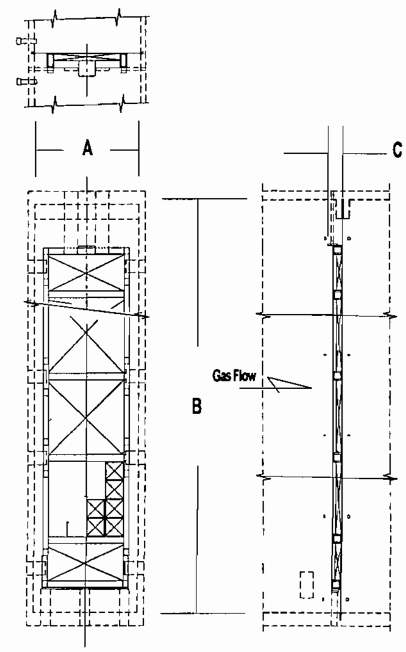


Table 4-4. Capital Costs for Oxidation Catalyst System, Eleven CT/HRSGs

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Purchased equipment	7,370,000	A
Sales tax	442,200	0.06 x A
Instrumentation	737,000	0.10 x A
Freight	368,500	0.05 x A
Subtotal Purchased Equipment	**8,917,700**	**B**
Installation		
Foundations and support	713,416	0.08 x B
Handling and erection	1,248,478	0.14 x B
Electrical	356,708	0.04 x B
Piping	178,354	0.02 x B
Insulation for ductwork	89,177	0.01 x B
Painting	89,177	0.01 x B
Subtotal Installation Cost	**2,675,310**	
Total Direct Costs (TDC)	**11,593,010**	
<u>Indirect Costs</u>		
Engineering	891,770	0.01 x B
Construction and field expense	445,885	0.05 x B
Contractor fees	891,770	0.10 x B
Startup	178,354	0.02 x B
Performance test	89,177	0.01 x B
Contingency	267,531	0.03 x B
Total Indirect Costs (TIC)	**2,764,487**	
TOTAL CAPITAL INVESTMENT (TCI)	**14,357,497**	TDC + TIC

Source: ECT, 2001.

Table 4-5. Annual Operating Costs for Oxidation Catalyst System, Eleven CT/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Catalyst costs		
Replacement (materials and labor)	7,337,616	
Credit for used catalyst	(990,000)	15% credit
Annualized Catalyst Cost	**1,548,124**	
Energy Penalties		
Turbine backpressure	1,081,159	0.2% penalty
Total Direct Costs (TDC)	**2,629,284**	
Indirect Costs		
Administrative charges	287,150	0.02 x TCI
Property taxes	143,575	0.01 x TCI
Insurance	143,575	0.01 x TCI
Capital recovery	770,745	15 yrs @ 7.0%
Total Indirect Costs (TIC)	**1,345,045**	
TOTAL ANNUAL COST (TAC)	**3,974,329**	TDC + TIC

Source: ECT, 2001.

Table 4-6. Summary of CO BACT Analysis (Revised August 2001)

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Rates (tpy)	Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
Oxidation catalyst	31.6	138.3	1,244.4	14,357,497	3,974,329	3,194	122,969	N	Y
Baseline	315.7	1,382.7	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Eleven GE PG7241 (FA) CTs, 100-percent load, natural gas-firing for 8,760 hr/yr.

Sources: ECT, 2001.
GE, 2001.
TEC, 2001.

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 26, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Additional Information
Project No. 0570040-015-AC
Bayside Units 3 and 4 Repowering Project

Dear Ms. Sheffield:

On June 26, 2001, the Department received the above referenced application. The modeling information in the application is incomplete. Rule 62-212.400(5)(d) requires a PSD Class I and Class II increment analysis for PM_{10}. This analysis was not provided. In order to continue processing your application, the Department will need this information

Any additional comments from EPA and the U.S. Fish and Wildlife Service will be forwarded to you after we receive them.

The Department will resume processing this 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. A new certification statement by the authorized representative or responsible official must accompany any material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days.

We will be happy to meet and discuss the details with you and your staff. You may discuss the modeling requirements with Mr. Cleve Holladay at 850/921-8689.

Sincerely,

for A.A. Linero, P.E. Administrator
New Source Review Section

AAL/sa

cc: G. Worley, EPA
J. Bunyak, NPS
B. Thomas, DEP-SWD
T. Davis, Ph.D., ECT

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* A Noel
B. Date of Delivery 7-28-01

C. Signature
X Alphaeus Noel
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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

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

2. Article Number *(Copy from service label)*
7000 0600 0026 4129 9242

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

7000 0600 0026 4129 9242

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

TAMPA FL 33619

Postage	$ $0.34
Certified Fee	$2.10
Return Receipt Fee (Endorsement Required)	$1.50
Restricted Delivery Fee (Endorsement Required)	$0.00
Total Postage & Fees	$ $3.94

0682
04
Postmark Here
TALLAHASSEE FL
07/26/2001

Recipient's Name (Please Print Clearly) (to be completed by mailer)
Ms. Karen Sheffield

Street, Apt. No.; or PO Box No.
Port Sutton Rd.

City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, February 2000 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 17, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: **Request for Additional Information**
Project No. 0570040-015-AC
Bayside Units 3 and 4 Re-powering Project

Dear Ms. Sheffield:

On June 26, 2001, the Department received your application and sufficient fee for an air construction permit to re-power the steam turbines for existing Gannon Units 3 and 4 with four combined cycle gas turbines to become part of the new Bayside Power Station. 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. Revised PSD Netting Analysis: In March of 2001, the Department issued a final permit for Bayside Units 1 and 2, which will re-power the steam turbines for existing Gannon Units 5 and 6. The application to re-power the steam turbines for existing Gannon Units 3 and 4 was submitted was submitted only three months later. The Department believes that this application is the second phase of the Gannon re-powering project. Please revise PSD netting analysis to include the following:
   - Specify the PSD contemporaneous period as defined in Rule 62-212.400(2)(e)3, F.A.C.
   - Include all emissions increases that have occurred or will occur during the contemporaneous period from all projects.
   - Include all of the emissions decreases that have occurred or will occur during the contemporaneous period from all projects.
   - Update the net emissions changes and PSD applicability accordingly.
2. Other Re-powering: Has TEC considered re-powering the existing steam turbines for Gannon Units 1 and 2? Has TEC contracted for any work involving the re-powering of these remaining steam turbines? Please submit a revised construction schedule for all units to be re-powered showing the planned startup date for each Bayside Unit and the shutdown date for each Gannon Unit.
3. Comparison of Bayside 1-2 with 3-4: Is TEC requesting any emissions standards, operational constraints, monitoring provisions, etc. that are different from those contained in the final permit issued for Bayside Units 1 and 2?

4. Emissions Decreases: Page 1-2 of the application states, "Following installation and commercial operation of Bayside Unit 3, existing coal fired operation at F.J. Gannon Station Unit 3 will permanently cease. Following installation and commercial operation of Bayside Unit 4, existing coal fired operation at F.J. Gannon Station Unit 4 will permanently cease." The Department notes that, for an emissions decrease to be enforceable, each existing unit must be completely shutdown and rendered incapable of operation prior to startup of the corresponding new unit. Please comment.

5. Unit Description: Each new "Bayside Unit" will consist of two combined cycle units described as:

   Each unit consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an unfired heat recovery steam generator (HRSG), a single exhaust stack that is 150 feet tall and 19.0 feet in diameter and associated support equipment. The project also includes electric fuel heaters and cooling towers. Natural gas is the exclusive fuel.

   Controls: Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC are minimized by the efficient combustion of natural gas at high temperatures. NOx emissions are reduced by a Selective Catalytic Reduction (SCR) system combined with dry low-NOx (DLN) combustion technology when firing natural gas.

   Heat Input: At a compressor inlet air temperature of 59° F and firing 1842 mmBTU (HHV) per hour of natural gas, each unit produces approximately 169 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 1,020,000 acfm at 215° F.

   Generating Capacity: Bayside Units 3A and 3B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 3) with a nameplate rating of 180 MW. Bayside Units 4A and 4B will supply steam to a single steam electrical generator (formerly serving Gannon Unit 4) with a nameplate rating of 188 MW of electrical power. Bayside Unit 3 is designed to produce a nominal 512 MW and Bayside Unit 4 is designed to produce a nominal 520 MW of electrical power.

   Is this an accurate description?

6. HAP Emissions: The Bayside 1 and 2 re-powering project combined with the Bayside 3 and 4 re-powering project will result in total formaldehyde emissions greater that 10 tons per year and total hazardous air pollutant emissions (HAP) greater that 25 tons per year. Please submit a case-by-case MACT analysis for the Department's review. The Department will make a case-by-case MACT determination for these phased projects.

7. Catalytic Oxidation System: Please provide a new vendor's quote for this project based on 11 proposed systems firing natural gas. Revise the cost analysis if necessary.

8. Air Quality Analysis: The Department reserves the right to ask for additional information regarding the air quality analysis within the 30-day period after receiving the application with sufficient fee (on or before July 26, 2001).

9. Other Reviews: The Department will forward any comments or questions if received from EPA Region 4, the National Park Service, the Hillsborough County Environmental Protection Commission, or the Department's Southwest District Office.

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 F. Koerner

Jeffery F. Koerner
New Source Review Section

AAL/jfk

cc: Mr. Patrick Shell, TEC
Mr. Shannon Todd, TEC
Mr. Tom Davis, ECT
Mr. Jerry Campbell, HCEPC
Mr. Gerald Kissel, SWD
Mr. Gregg Worley, 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:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Joseph Hernandez

B. Date of Delivery 7-19-01

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

2. Article Number *(Copy from service label)*
7000 0600 0026 4129 9150

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 0600 0026 4129 9150

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

Recipient's Name (Please Print Clearly) (to be completed by mailer)
Ms. Karen Sheffield, Gen. Mgr.

Street, Apt. No.; or PO Box No.
Port sutton Rd.

City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, February 2000 See Reverse for Instructions

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 2, 2001

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Tampa Electric Company
F.J. Gannon/Bayside Power Station
Project No. 0570040-015-AC

Dear Mr. Worley:

Enclosed for your review and comment is an application for a PSD source submitted by Tampa Electric Company. The proposed project is the construction of Units 3 and 4 at company's Bayside Power Station in Tampa, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Jeff Koerner, review engineer, at 850/921-9536.

Sincerely,

Patty Adams

fa Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa
Enclosure
cc: Jeff Koerner

"More Protection, Less Process"

Printed on recycled paper.

TAMPA ELECTRIC

RECEIVED
JUN 26 2001
BUREAU OF AIR REGULATION

June 25, 2001

Mr. Clair Fancy
Florida Department of Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Via FedEx
Airbill No.7900 8647 1419

Re: Bayside Power Station Units 3 and 4 Air Construction Permit Application Application Fee Submittal

Dear Mr. Fancy:

Please find enclosed a check in the amount of $7,500 submitted in support of the Bayside Power Station Units 3 and 4 Air Construction Permit Application. If you have questions, please contact Shannon Todd or me at (813) 641-5125.

Sincerely,

Laura R. Crouch

Laura R. Crouch
Manager-Air Programs
Environmental Affairs

EA\tl\SKT263

Enclosure

c: Mr. Jerry Kissel - FDEP SW
Ms. Alice Harman - EPCHC

TECO

TAMPA ELECTRIC

June 22, 2001

Mr. Clair Fancy
Florida Department of Environmental Protection
2600 Blair Stone Road
Twin Towers Office Building
Tallahassee, Florida 32399-2400

Hand Delivery

Re: Bayside Power Station Units 3 and 4 Air Construction Permit Application

Dear Mr. Fancy:

Please find enclosed six signed, sealed copies of the Bayside Power Station Units 3 and 4 Air Construction Permit Application. If you have questions, please contact Shannon Todd or me at (813) 641-5125.

Sincerely,

Karen A. Sheffield

Karen A. Sheffield
General Manager
Gannon Station

EA\tl\SKT261

Enclosures

c/enc: Mr. Jerry Kissel - FDEP SW
Ms. Alice Harman - EPCHC


BAYSIDE UNITS 3 & 4
AIR DISPERSION
MODELING FILES
ECT No. 991060-0100-1100
JUNE 2001

BAYSIDE POWER STATION
UNITS 3 AND 4
AIR CONSTRUCTION
PERMIT APPLICATION

Prepared for:

TECO

TAMPA ELECTRIC

Prepared by:

ECT

Environmental Consulting & Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 991060-0100

June 2001

TABLE OF CONTENTS

TABLE OF CONTENTS
(Continued, Page 2 of 2)

LIST OF TABLES

LIST OF FIGURES

1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Tampa Electric Company (TEC) is planning to repower its existing F.J. Gannon Station located on Port Sutton Road in Tampa, Hillsborough Country, Florida.

The TEC F.J. Gannon Station consists of six steam boilers (Units 1 through 6), six steam turbines, one simple-cycle combustion turbine (CT-1), a once-through cooling water system, storage and handling of solid fuels, fluxing material, fly ash, and slag, fuel oil storage tanks and ancillary support equipment. 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.

TEC is proposing to repower Units 3 and 4 at the F.J. Gannon Station by installing four General Electric (GE) 7FA CT/heat recovery steam generator (HRSG) units that will operate in conjunction with the existing Units 3 and 4 steam turbines (STs). The four new CT/HRSG units will be grouped into two units designated as Bayside Power Station (Bayside) Units 3 and 4. Bayside Units 3 and 4 will repower F.J. Gannon Station Units 3 and 4, respectively. Bayside Unit 3 will include two CT/HRSGs designated as CT-3A and CT-3B. Bayside Unit 4 will include two CT/HRSGs designated as CT-4A and CT-4B.

The HRSGs included with each CT will be unfired (i.e., the HRSGs will not include provisions for supplemental duct burner firing). The CT/HRSG units will not include HRSG by-pass stacks. Each CT will be equipped with an inlet air evaporative cooling system and will be fired exclusively with pipeline-quality natural gas. Ancillary equipment associated with Bayside Units 3 and 4 include cooling towers. The anhydrous ammonia required for the Bayside Units 3 and 4 selective catalytic reduction (SCR) control systems will be provided by either new storage tanks or the ammonia storage tanks planned for Bayside Units 1 and 2.

Bayside Units 3 and 4 will operate at an annual capacity factor of up to 100-percent. At base load operation, this annual capacity factor is equivalent to 8,760 hours per year (hr/yr) operation.

Following installation and commercial operation of Bayside Unit 3, existing coal fired operation at F.J. Gannon Station Unit 3 will permanently cease. Following installation and commercial operation of Bayside Unit 4, existing coal fired operation at F.J. Gannon Station Unit 4 will permanently cease. All Bayside Units 3 and 4 CT/HRSG units will be equipped with selective catalytic reduction (SCR) technology to control emissions of nitrogen oxides (NO_x). With the exception of carbon monoxide (CO) and particulate matter (PM/PM_{10}), there will be a substantial net reduction in emissions of all pollutants subject to review under the Prevention of Significant Deterioration (PSD) New Source Review (NSR) permitting program due to the repowering of F.J. Gannon Station Units 3 and 4 with Bayside Units 3 and 4. The net increases in CO, PM, and PM_{10} emissions due to the repowering of F.J. Gannon Station Units 3 and 4 with Bayside Units 3 and 4 will exceed the PSD significant emission rate for these pollutants. Accordingly, Bayside Units 3 and 4 are subject to the PSD NSR requirements of Section 62-212.400, Florida Administrative Code (F.A.C.) for CO, PM, and PM_{10} emissions.

Operation of the proposed Bayside Units 3 and 4 will result in airborne emissions. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This report, including the required permit application forms and supporting documentation included in the attachments, constitutes TEC's application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, F.A.C.

Bayside Units 3 and 4 will be located in an attainment area and will have net CO, PM, and PM_{10} emissions increases in excess of 100, 25, and 15 tons per year (tpy), respectively. Consequently, Bayside Units 3 and 4 qualify as a major modification to an existing major facility and are subject to the PSD NSR requirements of Rule 62-212.400, F.A.C. for CO, PM, and 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, PM, and PM_{10}.
- Sections 5.0 (Dispersion Modeling Methodology) and 6.0 (Dispersion Modeling Results) address ambient air quality impacts.

Attachments A through D provide the FDEP Application for Air Permit—Long Form, NO_x control system descriptions, emission rate calculations, and PSD netting analysis, respectively. All dispersion modeling input and output files for the ambient impact analysis are provided in Attachment E.

1.2 <u>SUMMARY</u>

Bayside Units 3 and 4 will consist of four combined-cycle CT/HRSG units. The CTs will be fired exclusively 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).

The planned construction start date for Bayside Units 3 and 4 is May 2002. The planned construction completion date for Bayside Units 3 and 4 is May 2004.

Based on an evaluation of the anticipated worst-case annual operating scenario, Bayside Units 3 and 4 will have the potential to emit 404.7 tpy of nitrogen oxides (NO_x), 502.8 tpy of carbon monoxide (CO), 355.7 tpy of particulate matter/particulate matter less than or equal to 10 micrometers (PM/PM_{10}), 180.8 tpy of sulfur dioxide (SO_2), 49.1 tpy of volatile organic compounds (VOCs), and 0.51 tpy of lead. Regarding noncriteria pollutants, Bayside Units 3 and 4 will potentially emit 33.2 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of 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 repowering of F.J. Gannon Station Units 3 and 4 with Bayside Units 3 and 4 will be below the Table212.400-2, F.A.C. Significant Emission Rates for all regulated air pollutants, with the exception of CO, PM, and PM_{10}. Accordingly, Bayside Units 3 and 4 are subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for CO, PM, and PM_{10} only. Based on actual historical emission rates adjusted for the retroactive application of NO_x, SO_2, and PM BACT, the repowering of F.J. Gannon Station Unit 3 and 4 with new Bayside Units 3 and 4 will result in a net decrease of 567.1 tpy of nitrogen oxides (NO_x), 571.9 tpy of sulfur dioxide (SO_2) 2.4 tpy of lead (Pb), and a net increase of 278.7 tpy of CO and 258.5 tpy of PM_{10} and PM. 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 will be controlled by the exclusive use of pipeline quality natural gas.
- NO_x emissions will be controlled by the use of dry low-NO_x (DLN) combustors and the use of SCR control technology. The controlled NO_x CT/HRSG exhaust concentration will be 3.5 parts per million by volume corrected to 15-percent oxygen (ppmvd at 15-percent O_2).
- Advanced burner design and good operating practices to minimize incomplete combustion will be employed to control CO emissions. Maximum short-term CO CT/HRSG exhaust concentration will be 7.8 ppmvd at 15-percent O_2. Cost effectiveness of a CO oxidation catalyst control system was determined to be \$3,302 per ton of CO. Due to the high control costs, in-

stallation 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 CT/HRSG VOC exhaust concentration is projected to be 1.3 ppmvd at 15-percent O_2.
- Bayside Units 3 and 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 Units 3 and 4 are 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).
- Analysis of the ambient air quality impacts due to operation of Bayside Units 3 and 4, together with the emissions associated with Bayside Units 1 and 2, demonstrates that maximum impacts will be well below all state and federal ambient air quality standards.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

Bayside Units 3 and 4 will be located at the existing Tampa Electric Company F.J. Gannon Station. The F.J. Gannon Station 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 F.J. Gannon Station site location and nearby prominent geographical features.

Bayside Units 3 and 4 will consist of four, combined-cycle GE PG7241 (FA) CTs. Each CT will be capable of producing a nominal 170 MW of electricity. The two Bayside Unit 3 combined-cycle CTs (designated as CT-3A and CT-3B) will repower F.J. Gannon Unit 3. Bayside Unit 3, including the repowered F.J. Gannon Station Unit 3 steam turbine (ST), will have a nominal generation capacity of 512 MW. The two Bayside Unit 4 combined-cycle CTs (designated as CT-4A and CT-4B) will repower F.J. Gannon Unit 4. Bayside Unit 4, including the repowered F.J. Gannon Station Unit 4 ST, will have a nominal generation capacity of 520 MW. The CTs will be fired exclusively with pipeline quality natural gas.

Bayside Units 3 and 4 will operate at an annual capacity factor of up to 100-percent. Capacity factor is defined as the ratio of the CT'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, this annual capacity factor is equivalent to 8,760 hours per year (hr/yr). The CTs will normally operate between 50- and 100-percent load.

Combustion of natural gas in the CTs 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 combined-cycle CTs include the use of DLN combustors and SCR control technology for abatement of NO_x; good combustion practices for control of CO and VOCs; and exclusive use of clean, low-sulfur, low-ash natural gas to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions.

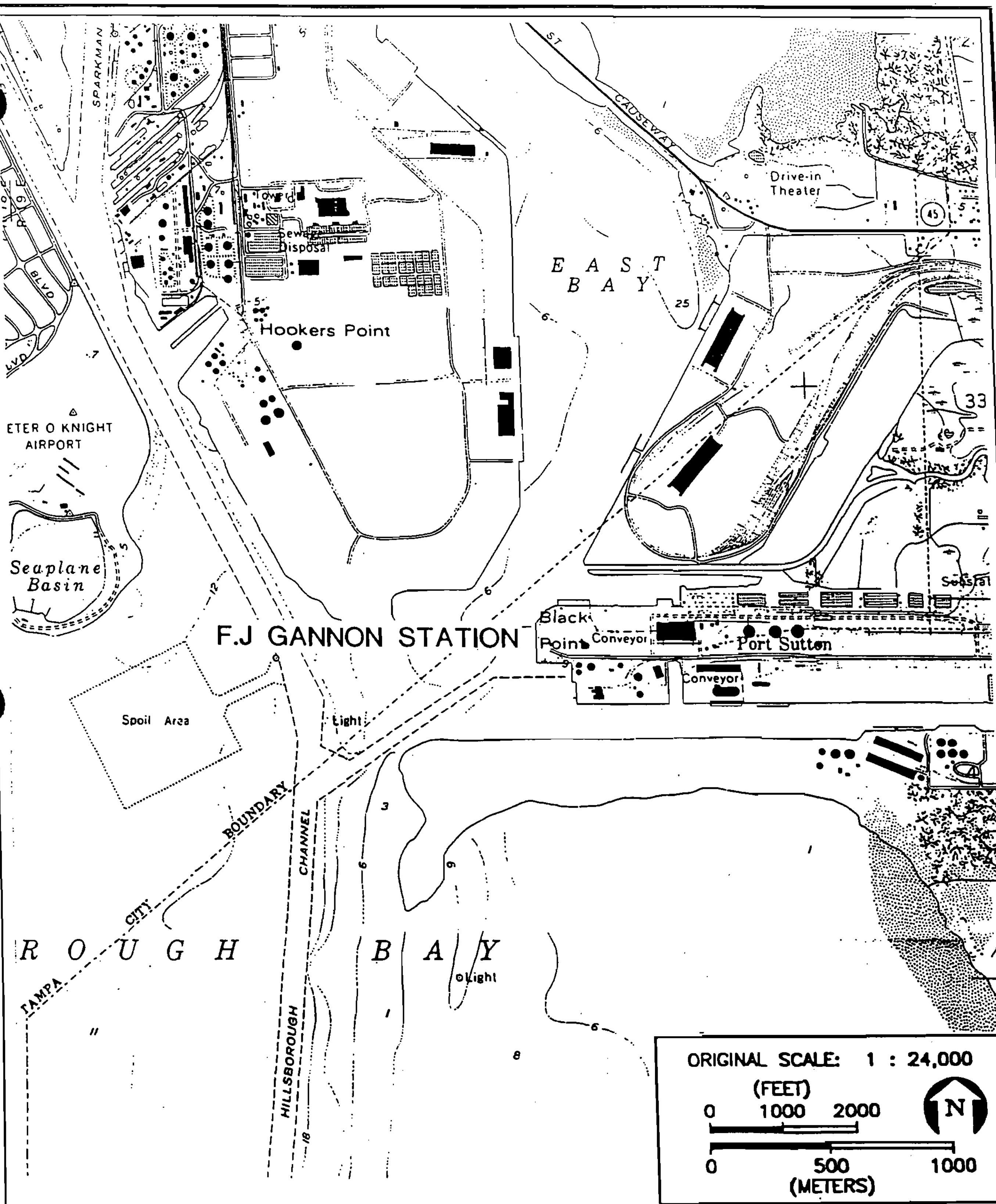


FIGURE 2-1.

F.J. GANNON STATION LOCATION AND SURROUNDINGS

Source: ECT, 2000.

ECT

Environmental Consulting & Technology, Inc.

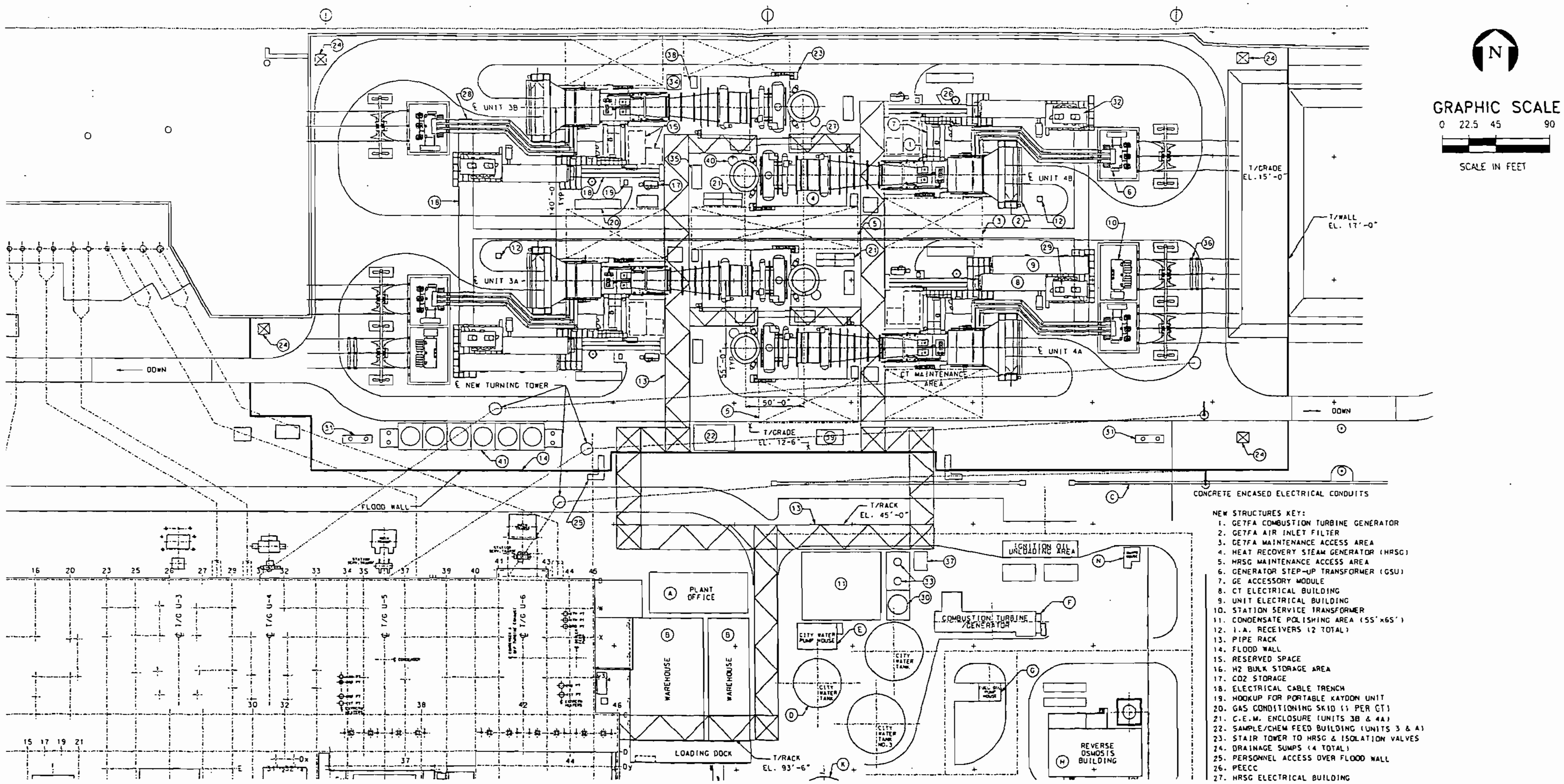
Figure 2-2 provides a plot plan of the Bayside Power Station showing the Bayside Units 3 and 4 layout, major process equipment and structures, and the new CT/HRSG emission points. A profile view of Bayside Units 3 and 4 is provided on Figure 2-3. Primary access to the Bayside Power Station will be from 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 Units 3 and 4 will include four nominal 170-MW CTs operating in combined-cycle mode. Figures 2-4 and 2-5 present process flow diagrams for Bayside Units 3 and 4, respectively.

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's turbine to produce rotary shaft power, which is used to drive an electric generator as well as the CT combustion air compressor.

The exhaust gases from each CT will then flow to a HRSG for the production of low-, intermediate-, and high-pressure steam. Steam produced by the two Bayside Unit 3 CT/HRSG units will be used to repower the existing F.J. Gannon Station Unit 3 ST. The Unit 3 ST, in turn, will drive an existing electric generator having a nominal generation capacity of 180 MW. Steam produced by the two Bayside Unit 4 CT/HRSG units will be used to repower the existing F.J. Gannon Station Unit 4 ST. The Unit 4 ST will drive an existing electric generator having a nominal generation capacity of 188 MW. The HRSGs will be unfired; i.e., the units will not include the capability of supplement duct burner



NEW STRUCTURES KEY:

1. GE7FA COMBUSTION TURBINE GENERATOR
2. GE7FA AIR INLET FILTER
3. GE7FA MAINTENANCE ACCESS AREA
4. HEAT RECOVERY STEAM GENERATOR (HRSG)
5. HRSG MAINTENANCE ACCESS AREA
6. GENERATOR STEP-UP TRANSFORMER (GSU)
7. GE ACCESSORY MODULE
8. CT ELECTRICAL BUILDING
9. UNIT ELECTRICAL BUILDING
10. STATION SERVICE TRANSFORMER
11. CONDENSATE POLISHING AREA (55'x65')
12. I.A. RECEIVERS (2 TOTAL)
13. PIPE RACK
14. FLOOD WALL
15. RESERVED SPACE
16. H2 BULK STORAGE AREA
17. CO2 STORAGE
18. ELECTRICAL CABLE TRENCH
19. HOOKUP FOR PORTABLE KAYDON UNIT
20. GAS CONDITIONING SKID (1 PER CT)
21. C.E.M. ENCLOSURE (UNITS 3B & 4A)
22. SAMPLE/CHEM FEED BUILDING (UNITS 3 & A)
23. STAIR TOWER TO HRSG & ISOLATION VALVES
24. DRAINAGE SUMPS (4 TOTAL)
25. PERSONNEL ACCESS OVER FLOOD WALL
26. PEECC
27. HRSG ELECTRICAL BUILDING
28. BAC
29. LCI & EX2100 (UNITS 3B & 4B)
30. POLISHER WASTE WATER TANK
31. OIL/WATER SEPRATORS (2 TOTAL)
32. EX2100 (UNITS 3A & 4A)
33. ACID & CAUSTIC TANKS
34. METAL CLEANING SUMP
35. FEEDWATER PUMP
36. TRANSMISSION CCVT (UNITS 3B & 4B)
37. AMINE SKIDS
38. SCR SKID
39. WATER WASH SKID (UNITS 3A & 4B)
40. BLOWDOWN TANK
41. CCW COOLING TOWERS

FOR INITIAL REVIEW

PLANT ARRANGEMENT STILL UNDER DEVELOPMENT

HRSG STACK LOCATIONS

UNIT	PLANT COORDINATES		STATE COORDINATES	
	NORTH	EAST	NORTH	EAST
3A	1700	3660	1299632.5650	520242.0058
3B	1840	3660	1299772.5622	520242.8847
4A	1645	3610	1299577.8800	520191.6614
4B	1785	3610	1299717.8772	520192.5404

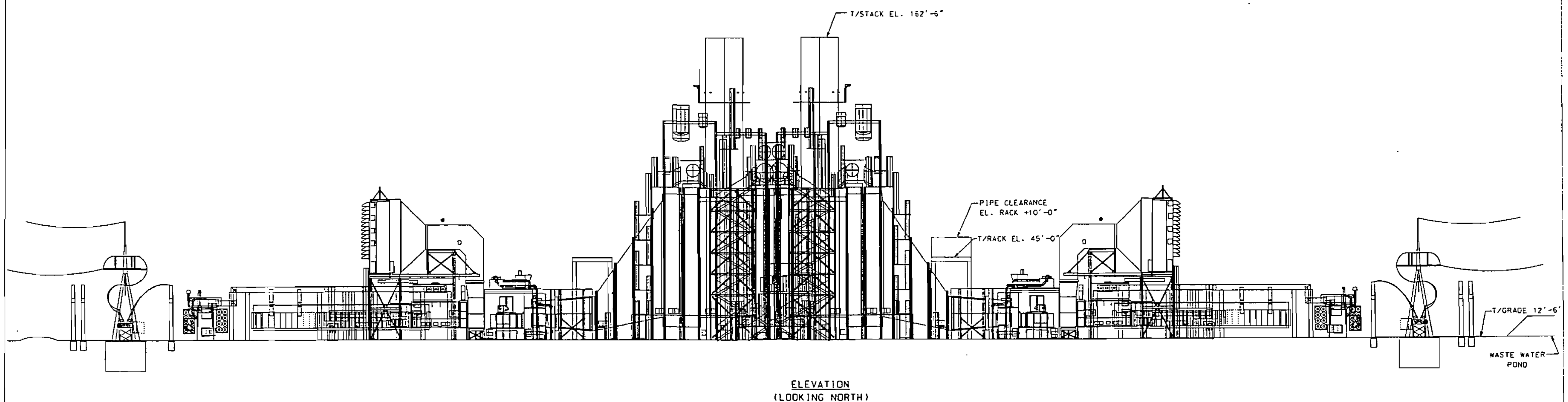
EXISTING STRUCTURES KEY:

A. PLANT OFFICE
B. WAREHOUSE
C. COVERED CABLE CONCRETE TRENCH
D. CITY WATER TANKS
E. CITY WATER PUMP HOUSE
F. COMBUSTION TURBINE/GENERATOR
G. FUEL OIL PUMP HOUSE
H. REVERSE OSMOSIS BUILDING
I. NOT USED
J. NOT USED
K. RECYCLE WATER TANK
L. BOILER SHOP
M. NOT USED
N. GUARD HOUSE
O. NOT USED
P. NOT USED
R. NOT USED
S. NOT USED

FIGURE 2-2.
BAYSIDE UNITS 3 AND 4 PLOT PLAN

SOURCE: Sargent & Lundy, 2001.

TECO
TAMPA ELECTRIC



FOR INITIAL REVIEW

PLANT ARRANGEMENT STILL UNDER DEVELOPMENT

GRAPHIC SCALE
0 14 27.5 55
SCALE IN FEET

FIGURE 2-3.
BAYSIDE UNITS 3 AND 4 PROFILE

SOURCE: Sargent & Lundy, 2001.

TECO
TAMPA ELECTRIC

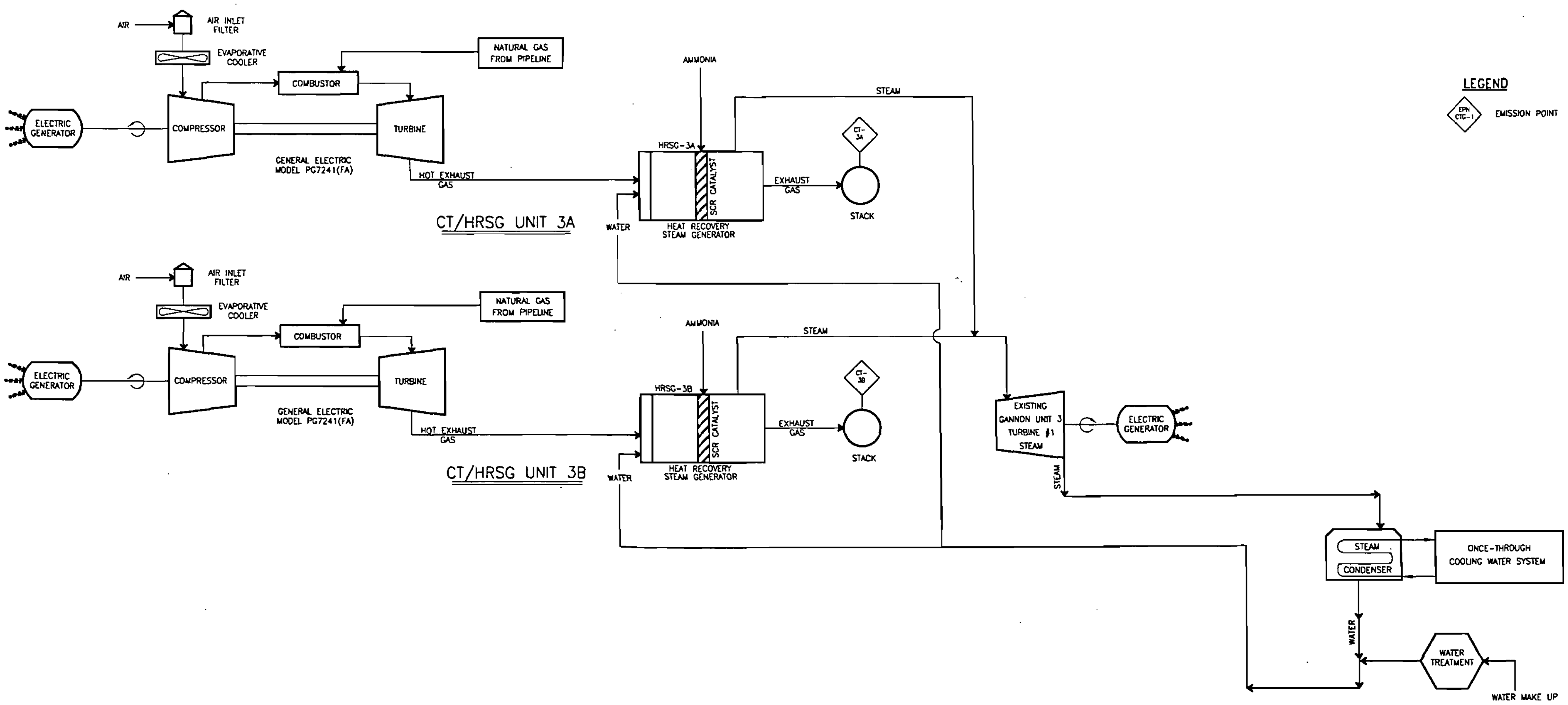


FIGURE 2-4.
PROCESS FLOW DIAGRAM - BAYSIDE UNIT 3

Source: TEC, 2001; ECT, 2001.

TECO
TAMPA ELECTRIC

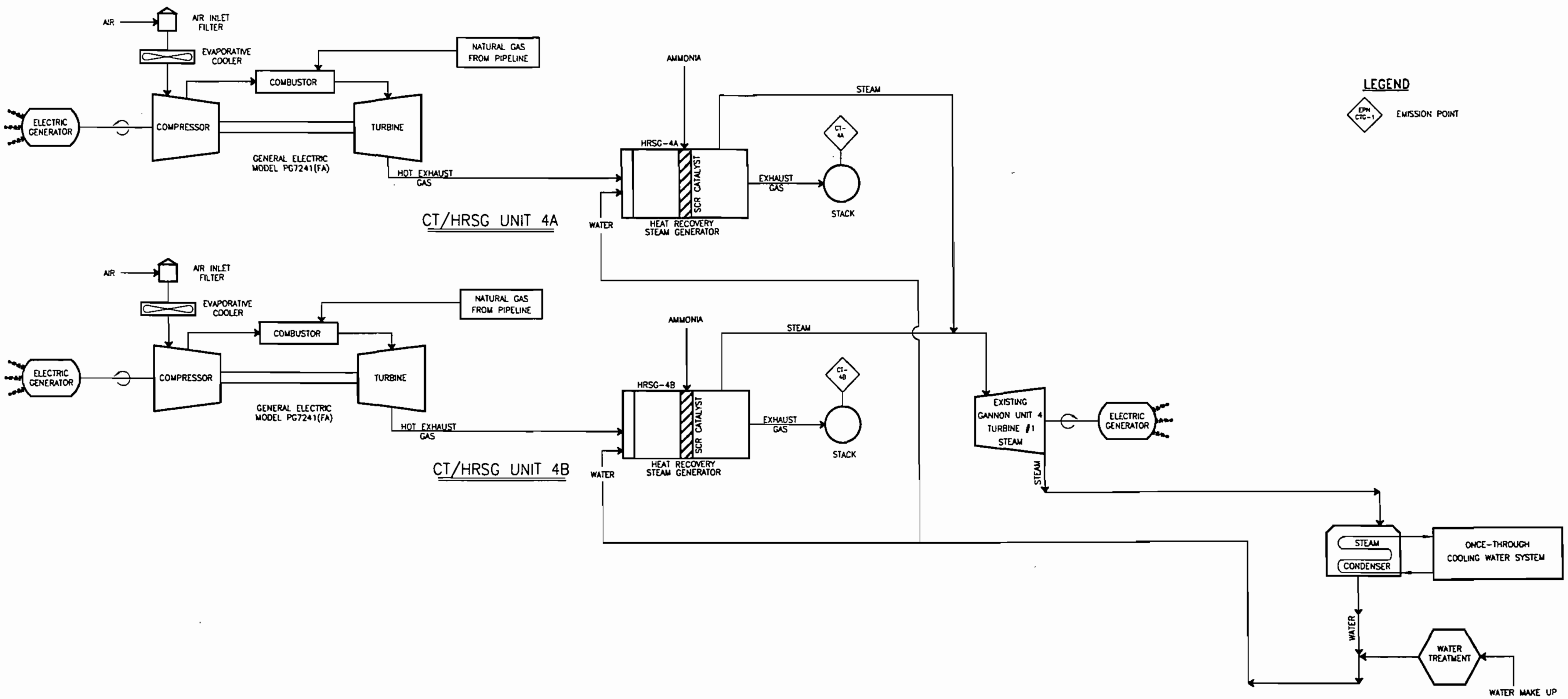


FIGURE 2-5.
PROCESS FLOW DIAGRAM - BAYSIDE UNIT 4

Source: TEC, 2001; ECT, 2001.

TECO
TAMPA ELECTRIC

firing. Following reuse of the CTs exhaust waste heat by the HRSGs, the exhaust gases are vented to the atmosphere.

Normal operation is expected to consist of all Bayside Units 3 and 4 CT/HRSGs firing natural gas at base load. Alternate operating modes include reduced load (i.e., between 50 and 100-percent of baseload) operation for one or more of the CT/HRSG units depending on power demands and CT inlet air evaporative cooling. CT/HRSG 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 Units 3 and 4 as specified in Section III., Condition 18.b. of Department Air Permit No. PSD-FL-301, Project No. 0570040-013-AC, recently issued for Bayside Units 1 and 2. As noted previously, the combined-cycle CT/HRSGs may operate at an annual capacity factor of up to 100-percent.

Vendor information indicates that the Bayside Unit 3 and 4 7FA CTs will have a heat input of 1,842 million British thermal units power hour (MMBtu/hr), higher heating value (HHV) at base load and 59°F ambient temperature. 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.

Rule 62-210.700(1), F.A.C., allows for excess emissions due to start-up, shut-down, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because CT/HRSG warm and cold start periods will last for 180 and 240 minutes, respectively, excess emissions for up to 4 hours in any 24-hour period are requested for the new CT/HRSGs. Excess emissions may also occur during a steam turbine cold startup. TEC therefore requests the same excess emission provisions for Bayside Units 3 and 4 as specified in Section III., Condition Nos. 18 and

25 of Department Air Permit No. PSD-FL-301, Project No. 0570040-013-AC, recently issued for Bayside Units 1 and 2.

The CTs will utilize DLN combustion technology and SCR to control NO_x air emissions. The exclusive use of low-sulfur natural gas in the CTs 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

Table 2-1 provides maximum hourly criteria pollutant CT/HRSG emission rates (per CT/HRSG unit). Maximum hourly H_2SO_4 emission rates are summarized in Table 2-2. Maximum hourly noncriteria pollutant rates are provided in Table 2-3. 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 CT/HRSG.

Maximum hourly emission rates for all pollutants, in units of pounds per hour (lb/hr), are projected to occur for CT/HRSG operations at base load and low ambient temperature (i.e., 18°F). The bases for these emission rates are provided in Attachment C.

Table 2-4 presents projected maximum annual criteria and noncriteria emissions for Bayside Units 3 and 4. The maximum annualized rates were conservatively estimated assuming base load operation for 8,760 hr/yr and an ambient temperature of 59°F. As noted previously, coal fired operation at existing F.J. Gannon Station Units 3 and 4 will cease following commercial operation of Bayside Units 3 and 4. The net annual change in emissions associated with the F.J. Gannon Station repowering project are shown in Table 2-5. Stack parameters for the CT/HRSG units are provided in Table 2-6.

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Four Temperatures (Per CT/HRGS)

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	18	20.5	2.58	11.1	1.39	24.7	3.11	31.1	3.92	3.0	0.38	0.031	0.0039
	59	20.3	2.56	10.3	1.30	23.1	2.91	28.7	3.62	2.8	0.35	0.029	0.0036
	72	20.3	2.56	10.1	1.27	22.6	2.85	27.8	3.50	2.7	0.34	0.028	0.0036
	93	20.2	2.55	9.8	1.23	21.9	2.76	26.9	3.39	2.7	0.34	0.027	0.0035
75	18	20.0	2.52	9.0	1.13	19.9	2.51	24.6	3.10	2.4	0.03	0.025	0.0032
	59	19.9	2.51	8.4	1.06	18.7	2.36	23.5	2.96	2.3	0.29	0.024	0.0030
	72	19.8	2.49	8.2	1.03	18.2	2.29	22.8	2.87	2.2	0.28	0.023	0.0029
	93	19.7	2.48	7.8	0.98	17.2	2.17	21.9	2.76	2.2	0.28	0.022	0.0028
50	18	19.6	2.47	7.2	0.91	15.8	1.99	20.4	2.57	2.0	0.25	0.020	0.0025
	59	19.5	2.46	6.8	0.85	14.8	1.86	19.5	2.46	1.9	0.24	0.019	0.0024
	72	19.5	2.46	6.6	0.83	14.4	1.81	19.1	2.41	1.8	0.23	0.018	0.0023
	93	19.4	2.44	6.2	0.79	13.7	1.73	18.6	2.34	1.8	0.23	0.018	0.0022

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible

*As measured by EPA Reference Methods 201 and 202.

Sources: ECT, 2001.
S&L, 2001.

Table 2-2. Maximum H_2SO_4 Pollutant Emission Rates for Three Loads and Four Ambient Temperatures (Per CT/HRSG)

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4	
		lb/hr	g/s
100	18	2.0	0.26
	59	1.9	0.24
	72	1.9	0.23
	93	1.8	0.23
75	18	1.6	0.21
	59	1.5	0.20
	72	1.5	0.19
	93	1.4	0.18
50	18	1.3	0.17
	59	1.2	0.16
	72	1.2	0.15
	93	1.1	0.14

Sources: ECT, 2001.
S&L, 2001.

Table 2-3. Maximum Noncriteria Pollutant Emission Rates for 100 Percent Load and Three Temperatures (Per CT/HRSG)

Unit Load (%)	Ambient Temp. (°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	18	0.00012	1.51E-05	0.085	1.07E-02	0.011	1.39E-03	0.036	4.54E-03	0.045	5.67E-03	0.225	2.84E-02
	59	0.00011	1.39E-05	0.079	9.95E-03	0.010	1.26E-03	0.034	4.28E-03	0.042	5.29E-03	0.210	2.65E-02
	93	0.00011	1.39E-05	0.075	9.45E-03	0.010	1.26E-03	0.032	4.03E-03	0.040	5.04E-03	0.199	2.51E-02

Unit Load (%)	Ambient Temp. (°F)	Mercury		Naphthalene		Polycyclic Aromatic Hydrocarbons		Propylene Oxide		Toluene		Xylene	
		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	18	1.5E-06	1.89E-07	0.0012	1.51E-04	0.0009	1.13E-04	0.056	7.09E-03	0.134	1.70E-02	0.128	1.62E-02
	59	1.4E-06	1.76E-07	0.0012	1.51E-04	0.0009	1.13E-04	0.053	6.71E-03	0.125	1.58E-02	0.120	1.52E-02
	93	1.4E-06	1.76E-07	0.0011	1.39E-04	0.0008	1.01E-04	0.050	6.33E-03	0.119	1.51E-02	0.114	1.44E-02

Note: g/s = gram per second.
lb/hr = pound per hour.

Source: ECT, 2001.

Table 2-4. Maximum Annual Emission Rates (tpy)

Pollutant	Bayside Units 3 and 4 (Both Units)
NO_x	404.7
CO	502.8
PM/PM_{10}*	355.7
SO_2	180.8
VOC	49.1
H_2SO_4 mist	33.2
1,3-Butadiene	0.002
Acetaldehyde	1.391
Acrolein	0.181
Benzene	0.590
Ethylbenzene	0.736
Formaldehyde	3.678
Lead	0.51
Mercury	0.000025
Naphthalene	0.020
Polycyclic Aromatic Hydrocarbons	0.015
Propylene Oxide	0.923
Toluene	2.194
Xylene	2.101

*As measured by EPA Reference Methods 201 and 202.

Sources: ECT, 2001.
TEC, 2001.
S&L, 2001.

Table 2-5. Net Annual Change in Emission Rates (tpy)

Pollutant	F.J. Gannon Station Units 3 & 4 Repowering Project
NO_x	-567.1
CO	278.7
PM/PM_{10}	258.5
SO_2	-571.9
VOC	-0.9
H_2SO_4 mist	-14.7
Pb	-2.4

Sources: ECT, 2001.
TEC, 2001.
S&L, 2000.

Table 2-6 Stack Parameters for Three Unit Loads and Four Ambient Temperatures (Per CT/HRSG)

Unit Load (%)	Ambient Temperature (°F)	Stack Height ft	Stack Height meters	Stack Exit Temperature °F	Stack Exit Temperature K	Stack Exit Velocity ft/sec	Stack Exit Velocity m/sec	Stack Diameter ft	Stack Diameter meters
100	18	150	45.7	233	385	66.3	20.2	19.0	5.8
	59	150	45.7	212	373	59.9	18.3	19.0	5.8
	72	150	45.7	215	375	59.0	18.0	19.0	5.8
	93	150	45.7	216	375	57.6	17.6	19.0	5.8
75	18	150	45.7	215	375	51.1	15.6	19.0	5.8
	59	150	45.7	212	373	49.0	14.9	19.0	5.8
	72	150	45.7	214	374	48.2	14.7	19.0	5.8
	93	150	45.7	215	375	46.5	14.2	19.0	5.8
50	18	150	45.7	201	367	41.5	12.6	19.0	5.8
	59	150	45.7	211	373	40.5	12.3	19.0	5.8
	72	150	45.7	213	374	40.1	12.2	19.0	5.8
	93	150	45.7	213	374	39.2	12.0	19.0	5.8

Note: K = Kelvin.
ft/sec = foot per second.
m/sec = meter per second.

Sources: ECT, 2001.
S&L, 2001.

3.0 AIR QUALITY STANDARDS AND NEW SOURCE REVIEW APPLICABILITY

3.1 NATIONAL AND STATE AAQS

As a result of the 1977 Clean Air Act (CAA) Amendments, the U.S. Environmental Protection Agency (EPA) has enacted primary and secondary NAAQS for six air pollutants (40 CFR 50). 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 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. The F.J. Gannon Station 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. 41 South and State Road 60 and a radius of 12 km, for SO_2, and for lead; the area encompassed within a radius of five km centered on 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 eight-hour ozone standard. However, due to litigation involving the new eight-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 [μg/m^3] unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards Primary	National Standards Secondary	Florida Standards
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[10,11]	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. U.S.E.P.A., 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 center-point at the intersection of U.S. 41 South and State Road 60 and a radius of 12 km), and for lead (the area encompassed within a radius of five 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

The Bayside Power Station will be located in Hillsborough County. As noted above, Hillsborough County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, Bayside Units 3 and 4 are 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 which 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 for the F.J. Gannon Station Units 3 and 4 repowering project will be below the significant emission rate thresholds, with the exception of CO, PM, and PM_{10}. Comparisons of estimated potential annual emission rates for the F.J. Gannon Units 3 and 4 repowering project and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of all regulated PSD pollutants, with the exception of CO, PM, and PM_{10}, are projected to be below the applicable PSD significant emission rate levels. Therefore, Bayside Units 3 and 4 qualify as a major modification to a major facility and are subject to the PSD NSR requirements of Section 62-212.400, F.A.C. for CO, PM, and PM_{10} only. Attachment D provides a detailed PSD netting analysis for the repowering project.

Table 3-2. Repowering Projected Emissions Compared to PSD Significant Emission Rates

Pollutant	Repowering Project Net Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	-567.1	40	No
CO	278.7	100	Yes
PM	258.5	25	Yes
PM_{10}	258.5	15	Yes
SO_2	-571.9	40	No
Ozone/VOC	-0.9	40	No
Lead	-2.4	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Negligible	3	No
H_2SO_4 mist	-14.7	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

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2001.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY

4.1 METHODOLOGY

The CO, PM, and 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 which 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) *Control Cost Manual* (EPA, 1996). Specific factors used in estimating capital and annual operating costs are summarized in Table 4-1.

Table 4-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
Direct Capital Costs	
Sales tax	0.06 x control system cost
Freight	0.05 x control system cost
Instrumentation	0.10 x control system cost
Foundations and supports	0.08 x purchased equipment cost
Handling and erection	0.14 x purchased equipment cost
Electrical	0.04 x purchased equipment cost
Piping	0.02 x purchased equipment cost
Insulation	0.01 x purchased equipment cost
Painting	0.01 x purchased equipment cost
Indirect Capital Costs	
Engineering	0.10 x purchased equipment cost
Construction and field expenses	0.05 x purchased equipment cost
Contractor fees	0.10 x purchased equipment cost
Start-up	0.02 x purchased equipment cost
Performance testing	0.01 x purchased equipment cost
Contingencies	0.03 x purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 x total operator labor cost
Maintenance labor	1.10 x operator labor direct wage
Maintenance materials	1.00 x total maintenance labor cost
Indirect Annual Operating Costs	
Overhead	0.60 x total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 x total capital investment
Property taxes	0.01 x total capital investment
Insurance	0.01 x total capital investment

Source: ECT, 2001.
EPA, 1996.

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, PM, and PM_{10} for Bayside Units 3 and 4 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 combustion products (PM/PM_{10}) and products of incomplete combustion (CO), 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 NSPS (40 CFR Part 60), NESHAP (40 CFR Parts 61 and 63), and 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 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 base load 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. The Bayside Units 3 and 4 CTs 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} or CO.

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.

The Bayside Power Station 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 Units 3 and 4, 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 Units 3 and 4.

Section 62-204.800, F.A.C., adopts federal NSPS and NESHAP, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines* is applicable to the Bayside Unit 3 and 4 CTs. 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 Units 3 and 4.

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 this fuel. Due to its low ash and sulfur contents, natural gas 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 have 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 and 4 CTs will be fired exclusively with natural gas. Combustion of natural gas will generate low PM/PM_{10} emissions in comparison to other fuels due to its low ash and sulfur contents. The minor PM/PM_{10} emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentration for the Bayside Units 3 and 4 CTs at baseload and 59°F is approximately 0.003 grains per dry standard cubic foot (gr/dscf). 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 CTs, the use of good combustion practices and clean fuels is considered to be BACT. The Bayside Units 3 and 4 CTs 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 CTs will be fired exclusively with pipeline quality natural gas. 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 CTs, the exclusive use of pipeline quality natural gas and efficient combustion design and operation is proposed as BACT for PM/PM_{10}. 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 4-2 summarizes the PM/PM_{10} BACT proposed for the Bayside Unit 3 and 4 CTs.

4.4 BACT ANALYSIS FOR CO

CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO 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 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 emissions.

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 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, combustion turbine vendors have had to con-

Table 4-2. Proposed PM/PM_{10} BACT

Emission Source	Proposed PM/PM_{10} BACT
GE PG7241 (FA) CT/HRSGs (Per CT/HRSG Unit)	Exclusive Use of Natural Gas Efficient Combustion Design and Operation 10.0 % Opacity [Indicator of Efficient Combustion Design and Operation]

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

sider the competing factors involved in NO_x and CO formation in order to develop units that achieve acceptable emission levels for both pollutants.

4.4.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO from gas turbines: (1) combustion process design and (2) 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 CTs, approximately 99 percent, CO emissions are inherently low.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO to carbon dioxide (CO_2) at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of CO oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO 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. The catalyst inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time which 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 combustion turbine applications, oxidation catalyst systems are typically designed to achieve a CO control efficiency of 80 to 90 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. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst 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 CT combustor design and oxidation catalyst control systems are considered to be technically feasible for the Bayside Units 3 and 4. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO is provided in the following sections.

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 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 CTs fired with natural gas.

Because CO emission rates from CTs 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 Units 3 and 4 (Hillsborough County) is classified attainment for all criteria pollutants, including CO. As noted in the Department's 1999 Air Monitoring Report, there have been no exceedances of the CO ambient air quality standards (AAQSs) in Florida during the last twelve years. Maximum CO concentrations for all Florida monitoring sites during 1999 were less than 30 percent of the 35 ppm one-hour AAQS, and less than 65 percent of the 9 ppm eight-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 3 and 4 CO emissions indicate that maximum CO impacts, without oxidation catalyst, will be insignificant. The highest, second highest 1- and 8-hour average CO impacts during natural gas-firing (the exclusive fuel for the Bayside Units 3 and 4) are projected to be only 0.3 and 0.5 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 the Bayside Units 3 and 4 CTs is projected to have a pressure drop across the catalyst bed of approximately 1.1 inch of water (H_2O). This pressure drop will result in a 0.22 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 3,276,240 kilowatt-hours (kwh) (11,179 MMBtu) per year at baseload (170-MW) operation and 100 percent capacity factor per CT. This energy penalty is equivalent to the use of 42.6 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 all four CTs. The lost power generation energy penalty, based on a power cost of $0.030/kwh, is $393,149 per year for all four CTs.

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 4-3. Specific capital

Table 4-3. 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: ECT, 2001.
TEC, 2001.

and annual operating costs for the oxidation catalyst control system are summarized in Tables 4-4 and 4-5, respectively.

The base case Bayside Units 3 and 4 annual CO emission rate (i.e., for all four CT /HRSG units) is 502.8 tpy based on CT baseload operation at 59°F for 8,760 hr/yr operation. The controlled annual CO emission rate, based on 90 percent control efficiency, is 50.3 tpy. Base case and controlled CO emission rates are summarized in Table 4-6.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be $3,302 per ton of CO removed. Based on the high control costs, use of oxidation catalyst technology to control CO emissions is not considered to be economically feasible. For example, the California San Joaquin Valley Unified Air Pollution Control District's BACT policy considers CO control costs of less than $300 per ton to be cost effective; i.e., CO control costs equal to or greater than $300 per ton are not considered cost effective. Results of the oxidation catalyst economic analysis are summarized in Table 4-6.

4.4.4 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO from CTs is typically required only for facilities located in CO nonattainment areas. A summary of recent FDEP CO BACT determinations for natural gas-fired combustion turbines is provided in Table 4-7.

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 CTs fired with natural gas. Because CO emission rates from CTs 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.

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 for recent CT projects.

Table 4-4. Capital Costs for Oxidation Catalyst System, Four CT/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	2,812,000	A
Sales tax	168,720	0.06 x A
Instrumentation	281,200	0.10 x A
Freight	140,600	0.05 x A
Subtotal Purchased Equipment	**3,402,520**	**B**
Installation		
Foundations and supports	272,202	0.08 x B
Handling and erection	476,353	0.14 x B
Electrical	136,101	0.04 x B
Piping	68,050	0.02 x B
Insulation for ductwork	34,025	0.01 x B
Painting	34,025	0.01 x B
Subtotal Installation Cost	**1,020,756**	
Total Direct Costs (TDC)	**4,423,276**	
Indirect Costs		
Engineering	340,252	0.10 x B
Construction and field expenses	170,126	0.05 x B
Contractor fees	340,252	0.10 x B
Startup	68,050	0.02 x B
Performance test	34,025	0.01 x B
Contingency	102,076	0.03 x B
Total Indirect Costs (TIC)	**1,054,781**	
TOTAL CAPITAL INVESTMENT (TCI)	**5,478,057**	TDC + TIC

Source: ECT, 2001

Table 4-5. Annual Operating Costs for Oxidation Catalyst System, Four CT/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Catalyst costs		
Replacement (materials and labor)	2,774,784	
Credit for used catalyst	(374,400)	15% credit
Annualized Catalyst Costs	**585,431**	
Energy Penalties		
Turbine backpressure	393,149	0.2% penalty
Total Direct Costs (TDC)	**978,580**	
Indirect Costs		
Administrative charges	109,561	0.02 x TCI
Property taxes	54,781	0.01 x TCI
Insurance	54,781	0.01 x TCI
Capital recovery	296,805	15 yrs @ 7.0%
Total Indirect Costs (TIC)	**515,927**	
TOTAL ANNUAL COST (TAC)	**1,494,507**	TDC + TIC

Sources: ECT, 2001
TEC, 2001

Table 4-6. Summary of CO BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	(tpy)	Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
Oxidation catalyst	11.5	50.3	452.5	5,478,057	1,494,507	3,302	44,716	N	Y
Baseline	114.8	502.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Four GE PG7241 (FA) CTs, 100-percent load for 8,760 hr/yr.

Sources: ECT, 2001.
GE, 2001.
TEC, 2001.

Table 4-7 Florida BACT CO Summary—Natural Gas-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
9/28/95	City of Key West	23	20	Good combustion
5/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
7/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
9/28/98	Florida Power Corp. Hines Energy Complex	165	25	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	12	Good combustion
12/4/98	Santa Rosa Energy, LLC (DB Off)	167	9	Good combustion
12/4/98	Santa Rosa Energy, LLC (DB On)	167	24	Good combustion
7/23/99	Seminole Electric Cooperative, Inc., Payne Creek	158	20	Good combustion
10/8/99	Tampa Electric Company -- Polk Power Station	165	15	Good combustion
10/8/99	TECO Power Services – Hardee Power Station	75	25	Good combustion
10/18/99	Vandolah Power Project	170	12	Good combustion
12/28/99	Reliant Energy Osceola	170	10.5	Good combustion
1/13/00	Shady Hills Generating Station	170	12	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3 (DB Off)	167	12	Good combustion
2/00	Kissimmee Utility – Cane Island Unit 3 (DB On)	167	20	Good combustion
2/24/00	Gainesville Regional Utilities	83	25	Good combustion
5/11/00	Calpine Osprey (Draft – DB Off)	170	10	Good combustion
5/11/00	Calpine Osprey (Draft – DB On)	170	17	Good combustion
7/31/00	Gulf Power – Smith Unit 3 (DB On)	170	16	Good combustion
1/29/01	CPV Gulfcoast, Ltd. (Power Augmentation Off)	170	9	Good combustion
1/29/01	CPV Gulfcoast, Ltd. (Power Augmentation On)	170	15	Good combustion
3/30/01	Tampa Electric Company – Bayside Units 1 & 2	170	9	Good combustion

Source: FDEP, 2001.

Maximum CO exhaust concentrations from the CT/HRSG units will be less than or equal to 9.0 ppmvd, respectively. This CO exhaust concentration is consistent with recent FDEP CO BACT determinations for CT/HRSG units. CO BACT emission limits proposed for Bayside Units 3 and 4 are provided in Table 4-8. The CO BACT limits shown in Table 4-8 are consistent with the limits recently approved by the Department for Bayside Units 1 and 2.

Table 4-8. Proposed CO BACT Emission Limits

Emission Source	Proposed CO BACT Emission Limits ppmvd*	lb/hr†
GE PG7241 (FA) CT/HRSGs (Per CT/HRSG Unit)		
CO (Natural Gas)	7.8‡ (9.0**)	28.7

* Corrected to 15 percent oxygen.
† CT compressor inlet air temperature of 59°F.
‡ 3-run test average determined by EPA Method 10.
** 24-hour block average using CO CEMS.

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

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 Units 3 and 4 will have the potential to emit 404.7 tpy of NO_x, 502.8 tpy of CO, 355.7 tpy of PM/PM_{10}, 180.8 tpy of SO_2, 49.1 tpy of VOCs, and 33.2 tpy of H_2SO_4 mist. Table 3-2 previously provided estimated potential annual emission rates increases for the F.J. Gannon Units 3 and 4 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 Units 3 and 4 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 request from the FDEP, an air quality impact analysis for Bayside Units 3 and 4 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 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 center line (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 center line, is defined as intermediate terrain.

USGS 7.5-minute series topographic maps were examined for terrain features in the vicinity of the Bayside Power Station (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, assign-

Table 5-1. Building/Structure Dimensions

Building/Structure	Dimensions Width (meters)	Length (meters)	Height (meters)
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

Sources: ECT, 2001.
TEC, 2001.

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." The entire perimeter of the F.J. Gannon Station/Bayside Power Station 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 ($^{\circ}$) 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 dispersion modeling studies of the F.J. Gannon Station submitted to the 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.

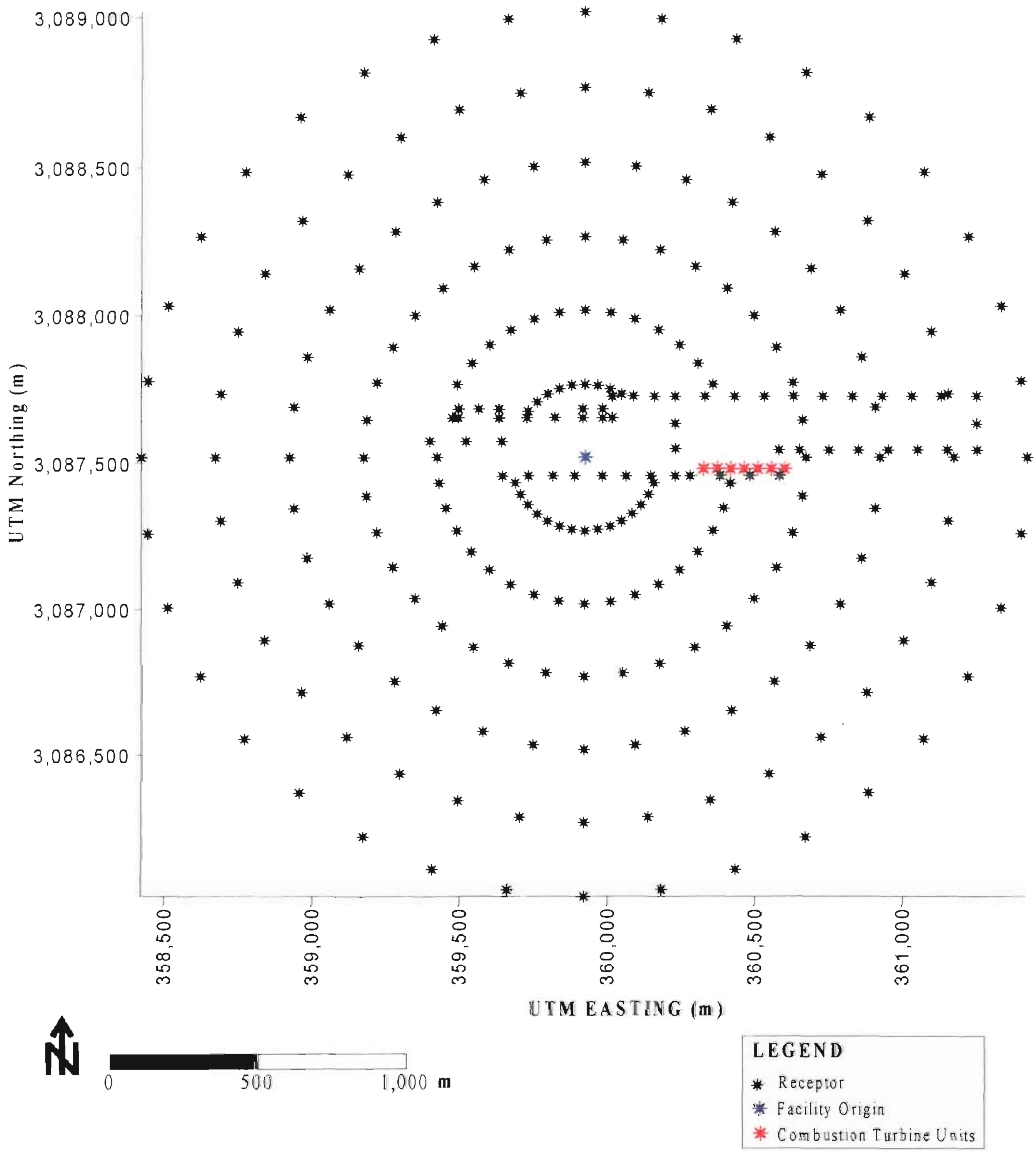


FIGURE 5-1.
RECEPTOR LOCATIONS (WITHIN 1,500 m)

ECT
Environmental Consulting & Technology, Inc.

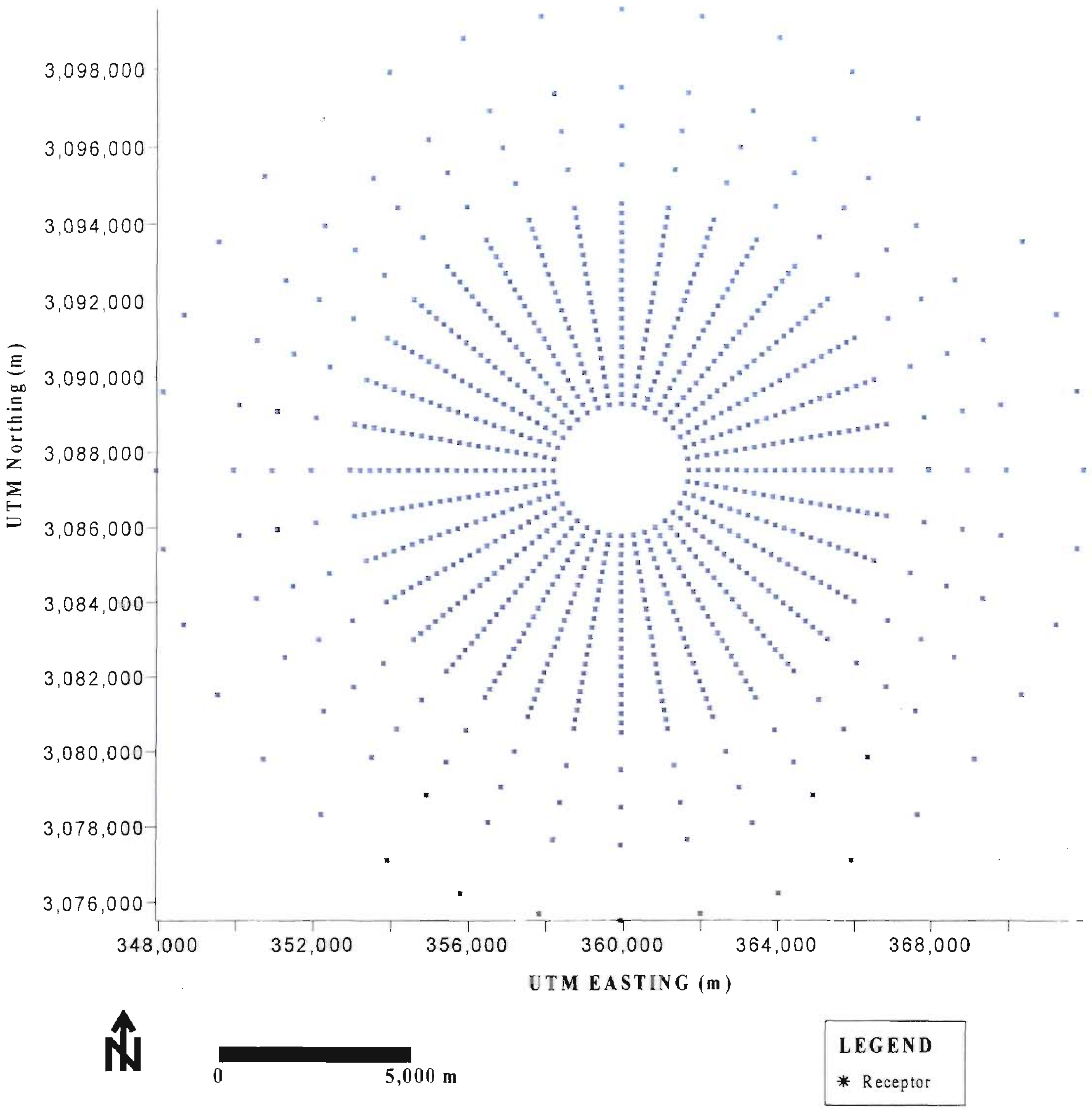


FIGURE 5-2.
RECEPTOR LOCATIONS (From 1,500m to 12 km)

ECT
Environmental Consulting & Technology, Inc.

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.

5.10 MODELED EMISSION INVENTORY

As requested by the Department, the modeled on-property emission sources consisted of the eleven Bayside Units 1 through 4 combined-cycle CT/HRSGs. Refined modeling was conducted for each of the 12 operating cases.

Emission rates and stack parameters for the Bayside Units 3 and 4 CT/HRSGs 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 12 Bayside Units 1 through 4 operating scenarios during natural gas-firing. These operating scenarios include three loads (50, 75, and 100 percent) and four ambient temperatures (18, 59, 72, and 93°F). ISCST3 model results for each year of meteorology evaluated (1992 through 1996) for SO_2, NO_2, PM/PM_{10}, and CO impacts are summarized on Table 6-1.

Maximum highest, second highest (HSH) 3- and 24-hour SO_2 impacts are projected to be 91.3 and 22.9 $\mu g/m^3$, respectively. The 3-hour HSH SO_2 impact is 7.0 percent of the Federal and Florida 3-hour average Ambient Air Quality Standard (AAQS) of 1,300 $\mu g/m^3$. The 24-hour HSH SO_2 impact is 6.3 and 8.8 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 2.0 $\mu g/m^3$. This impact is 2.5 and 3.3 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 3.3 $\mu g/m^3$. This impact is 3.3 percent of the Federal and Florida annual average AAQS of 100 $\mu g/m^3$.

Maximum highest, second highest (HSH) 24-hour PM/PM_{10} impact is projected to be 58.9 $\mu g/m^3$. This impact is 39.3 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 5.5 $\mu g/m^3$. This impact is 11.1 percent of the Federal and Florida annual average AAQS of 50 $\mu g/m^3$.

Maximum highest, second highest (HSH) 1- and 8-hour CO impacts are projected to be 261.5 and 174.8 $\mu g/m^3$, respectively. These impacts are 0.7 and 1.7 percent of the Federal and Florida 1- and 8-hour average AAQS of 40,000 and 10,000 $\mu g/m^3$, respectively.

Table 6-1. Air Quality Impact Analysis Summary
Natural Gas-Firing (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
Nominal 10 g/s Impacts:																				
HSH, 1-Hour ($\mu g/m^3$)	621.3	625.4	632.3	613.1	615.7	739.9	743.9	735.2	747.8	732.4	1,017.5	953.4	966.4	1,003.4	939.3	675.8	680.6	676.7	670.1	658.9
HSH, 3-Hour ($\mu g/m^3$)	411.7	463.2	419.9	450.2	431.8	526.1	575.2	481.0	521.9	510.0	559.5	622.9	610.1	599.3	596.0	466.2	498.5	472.4	496.3	478.0
HSH, 8-Hour ($\mu g/m^3$)	227.7	251.6	264.5	275.8	267.6	258.7	275.5	322.6	336.6	325.3	284.4	292.7	375.8	358.7	325.8	234.2	252.8	282.0	309.7	295.7
HSH, 24-Hour ($\mu g/m^3$)	125.5	109.8	121.1	151.0	136.2	169.8	158.9	159.3	201.9	191.5	186.4	180.9	199.2	236.6	227.9	150.0	132.3	133.5	168.5	158.3
Annual ($\mu g/m^3$)	7.0	5.2	8.2	7.7	9.6	11.5	9.3	12.7	12.3	16.1	16.6	13.2	16.7	16.7	22.0	8.7	6.9	10.2	9.7	12.4
SO_2																				
Emission Rate (g/s)	1.39	1.39	1.39	1.39	1.39	1.13	1.13	1.13	1.13	1.13	0.91	0.91	0.91	0.91	0.91	1.30	1.30	1.30	1.30	1.30
HSH, 3-Hour ($\mu g/m^3$)	57.2	64.4	58.4	62.6	60.0	59.4	65.0	54.3	84.5	57.6	50.9	56.7	55.5	91.3	54.2	60.6	64.8	61.4	64.5	62.1
HSH, 24-Hour ($\mu g/m^3$)	17.5	15.3	16.8	21.0	18.9	19.2	18.0	18.0	22.8	21.6	17.0	16.5	18.1	21.5	20.7	19.5	17.2	17.4	21.9	20.6
Annual ($\mu g/m^3$)	1.0	0.7	1.1	1.1	1.3	1.3	1.0	1.4	1.4	1.8	1.5	1.2	1.5	1.5	2.0	1.1	0.9	1.3	1.3	1.6
NO_2																				
Emission Rate (g/s)	3.11	3.11	3.11	3.11	3.11	2.51	2.51	2.51	2.51	2.51	1.99	1.99	1.99	1.99	1.99	2.91	2.91	2.91	2.91	2.91
Tier 2 Annual ($\mu g/m^3$)	1.6	1.2	1.9	1.8	2.2	2.2	1.7	2.4	2.3	3.0	2.5	2.0	2.5	2.5	3.3	1.9	1.5	2.2	2.1	2.7
PM/PM_{10}																				
Emission Rate (g/s)	2.58	2.58	2.58	2.58	2.58	2.52	2.52	2.52	2.52	2.52	2.47	2.47	2.47	2.47	2.47	2.56	2.56	2.56	2.56	2.56
HSH, 24-Hour ($\mu g/m^3$)	32.4	28.3	31.2	39.0	35.1	42.8	40.0	40.1	50.9	48.3	46.0	44.7	49.2	58.4	56.3	38.4	33.9	34.2	43.1	40.5
Annual ($\mu g/m^3$)	1.8	1.4	2.1	2.0	2.5	2.9	2.3	3.2	3.1	4.1	4.1	3.3	4.1	4.1	5.4	2.2	1.8	2.6	2.5	3.2
CO																				
Emission Rate (g/s)	3.92	3.92	3.92	3.92	3.92	3.10	3.10	3.10	3.10	3.10	2.57	2.57	2.57	2.57	2.57	3.62	3.62	3.62	3.62	3.62
HSH, 1-Hour ($\mu g/m^3$)	243.5	245.1	247.9	240.3	241.3	229.4	230.6	227.9	231.8	227.0	261.5	245.0	248.4	257.9	241.4	244.6	246.4	245.0	242.6	238.5
HSH, 8-Hour ($\mu g/m^3$)	89.3	98.6	103.7	108.1	104.9	80.2	85.4	100.0	104.3	100.8	73.1	75.2	96.6	92.2	83.7	84.8	91.5	102.1	112.1	107.0

Table 6-1. Air Quality Impact Analysis Summary
Natural Gas-Firing (Page 2 of 3)

	Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)					Case 7 (100% Load, 72°F Ambient)					Case 8 (75% Load, 72°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:																				
HSH, 1-Hour ($\mu g/m^3$)	807.0	774.2	765.4	792.4	760.9	1,016.6	954.7	966.7	1,003.6	940.7	681.5	685.4	679.6	675.7	662.6	819.4	777.8	772.3	805.1	765.9
HSH, 3-Hour ($\mu g/m^3$)	543.2	570.4	509.4	541.6	534.7	559.3	622.7	610.2	599.4	596.9	470.8	501.0	477.1	499.5	483.7	546.3	572.6	514.8	546.4	541.1
HSH, 8-Hour ($\mu g/m^3$)	272.2	285.1	355.2	358.3	333.4	284.7	294.9	375.4	358.9	326.0	235.4	254.5	285.1	311.3	297.7	273.6	286.2	357.5	360.3	335.0
HSH, 24-Hour ($\mu g/m^3$)	174.7	169.5	164.1	216.3	199.4	187.6	180.6	199.4	236.7	228.4	152.8	134.2	135.5	169.8	160.7	175.8	170.9	165.6	218.0	201.3
Annual ($\mu g/m^3$)	12.4	10.0	13.6	13.2	17.4	16.6	13.2	16.7	16.7	22.1	8.9	7.0	10.4	9.8	12.6	12.6	10.2	13.7	13.4	17.7
SO_2																				
Emission Rate (g/s)	1.06	1.06	1.06	1.06	1.06	0.85	0.85	0.85	0.85	0.85	1.27	1.27	1.27	1.27	1.27	1.03	1.03	1.03	1.03	1.03
HSH, 3-Hour ($\mu g/m^3$)	57.6	60.5	54.0	57.4	56.7	47.5	52.9	51.9	85.3	50.7	59.8	63.6	60.6	85.8	61.4	56.3	59.0	53.0	82.9	55.7
HSH, 24-Hour ($\mu g/m^3$)	18.5	18.0	17.4	22.9	21.1	15.9	15.3	17.0	20.1	19.4	19.4	17.0	17.2	21.6	20.4	18.1	17.6	17.1	22.5	20.7
Annual ($\mu g/m^3$)	1.3	1.1	1.4	1.4	1.8	1.4	1.1	1.4	1.4	1.9	1.1	0.9	1.3	1.3	1.6	1.3	1.0	1.4	1.4	1.8
NO_2																				
Emission Rate (g/s)	2.36	2.36	2.36	2.36	2.36	1.86	1.86	1.86	1.86	1.86	2.85	2.85	2.85	2.85	2.85	2.29	2.29	2.29	2.29	2.29
Tier 2 Annual ($\mu g/m^3$)	2.2	1.8	2.4	2.3	3.1	2.3	1.8	2.3	2.3	3.1	1.9	1.5	2.2	2.1	2.7	2.2	1.7	2.4	2.3	3.0
PM/PM_{10}																				
Emission Rate (g/s)	2.51	2.51	2.51	2.51	2.51	2.46	2.46	2.46	2.46	2.46	2.56	2.56	2.56	2.56	2.56	2.49	2.49	2.49	2.49	2.49
HSH, 24-Hour ($\mu g/m^3$)	43.8	42.5	41.2	54.3	50.0	46.1	44.4	49.1	58.2	56.2	39.1	34.4	34.7	43.5	41.1	43.8	42.5	41.2	54.3	50.1
Annual ($\mu g/m^3$)	3.1	2.5	3.4	3.3	4.4	4.1	3.2	4.1	4.1	5.4	2.3	1.8	2.7	2.5	3.2	3.1	2.5	3.4	3.3	4.4
CO																				
Emission Rate (g/s)	2.96	2.96	2.96	2.96	2.96	2.46	2.46	2.46	2.46	2.46	3.50	3.50	3.50	3.50	3.50	2.87	2.87	2.87	2.87	2.87
HSH, 1-Hour ($\mu g/m^3$)	238.9	229.2	226.5	234.6	225.2	250.1	234.8	237.8	246.9	231.4	238.5	239.9	237.9	236.5	231.9	235.2	223.2	221.6	231.1	219.8
HSH, 8-Hour ($\mu g/m^3$)	80.6	84.4	105.2	160.3	98.7	70.0	72.5	92.3	88.3	80.2	82.4	89.1	99.8	174.8	104.2	78.5	82.1	102.6	103.4	96.1

Table 6-1. Air Quality Impact Analysis Summary
Natural Gas-Firing (Page 3 of 3)

	Case 9 (50% Load, 72°F Ambient)					Case 10 (100% Load, 93°F Ambient)					Case 11 (75% Load, 93°F Ambient)					Case 12 (50% Load, 93°F Ambient)					Maximums
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	
Nominal 10 g/s Impacts:																					
HSH, 1-Hour ($\mu g/m^3$)	1,020.5	958.9	970.7	1,007.7	944.6	691.0	694.0	685.8	687.5	670.7	856.8	796.4	809.1	842.8	798.4	1,035.7	974.2	985.9	1,023.1	958.2	1,035.7
HSH, 3-Hour ($\mu g/m^3$)	560.1	623.6	612.2	600.5	598.0	480.4	506.2	486.1	506.2	494.4	535.8	546.4	527.8	541.1	559.8	563.5	560.3	619.9	604.7	601.8	623.6
HSH, 8-Hour ($\mu g/m^3$)	285.9	297.6	376.0	359.8	326.3	237.9	258.2	291.0	314.6	302.1	275.2	261.6	347.7	341.0	334.6	290.0	311.8	378.5	367.9	310.8	378.5
HSH, 24-Hour ($\mu g/m^3$)	185.9	181.0	200.4	237.3	229.1	158.7	138.3	139.5	175.5	165.2	178.4	171.2	170.0	222.8	205.6	187.4	184.0	204.4	241.3	232.9	241.3
Annual ($\mu g/m^3$)	16.7	13.3	16.8	16.8	22.2	9.4	7.5	10.7	10.2	13.1	13.3	10.6	14.3	14.0	18.5	17.2	13.6	17.1	17.1	22.7	22.7
SO_2																					
Emission Rate (g/s)	0.83	0.83	0.83	0.83	0.83	1.23	1.23	1.23	1.23	1.23	0.98	0.98	0.98	0.98	0.98	0.79	0.79	0.79	0.79	0.79	1.4
HSH, 3-Hour ($\mu g/m^3$)	46.5	51.8	50.8	83.6	49.6	59.1	62.3	59.8	62.3	60.8	52.5	53.6	51.7	82.6	54.9	44.5	44.3	49.0	80.8	47.5	91.3
HSH, 24-Hour ($\mu g/m^3$)	15.4	15.0	16.6	19.7	19.0	19.5	17.0	17.2	21.6	20.3	17.5	16.8	16.7	21.8	20.1	14.8	14.5	16.1	19.1	18.4	22.9
Annual ($\mu g/m^3$)	1.4	1.1	1.4	1.4	1.8	1.2	0.9	1.3	1.3	1.6	1.3	1.0	1.4	1.4	1.8	1.4	1.1	1.4	1.4	1.8	2.0
NO_2																					
Emission Rate (g/s)	1.81	1.81	1.81	1.81	1.81	2.76	2.76	2.76	2.76	2.76	2.17	2.17	2.17	2.17	2.17	1.73	1.73	1.73	1.73	1.73	3.1
Tier 2 Annual ($\mu g/m^3$)	2.3	1.8	2.3	2.3	3.0	1.9	1.5	2.2	2.1	2.7	2.2	1.7	2.3	2.3	3.0	2.2	1.8	2.2	2.2	2.9	3.3
PM/PM_{10}																					
Emission Rate (g/s)	2.46	2.46	2.46	2.46	2.46	2.55	2.55	2.55	2.55	2.55	2.48	2.48	2.48	2.48	2.48	2.44	2.44	2.44	2.44	2.44	2.6
HSH, 24-Hour ($\mu g/m^3$)	45.7	44.5	49.3	58.4	56.4	40.5	35.3	35.6	44.8	42.1	44.2	42.4	42.2	55.3	51.0	45.7	44.9	49.9	58.9	56.8	58.9
Annual ($\mu g/m^3$)	4.1	3.3	4.1	4.1	5.5	2.4	1.9	2.7	2.6	3.4	3.3	2.6	3.6	3.5	4.6	4.2	3.3	4.2	4.2	5.5	5.5
CO																					
Emission Rate (g/s)	2.41	2.41	2.41	2.41	2.41	3.39	3.39	3.39	3.39	3.39	2.76	2.76	2.76	2.76	2.76	2.34	2.34	2.34	2.34	2.34	3.9
HSH, 1-Hour ($\mu g/m^3$)	245.9	231.1	233.9	242.9	227.6	234.3	235.3	232.5	233.1	227.4	236.5	219.8	223.3	232.6	220.4	242.4	228.0	230.7	239.4	224.2	261.5
HSH, 8-Hour ($\mu g/m^3$)	68.9	71.7	90.6	86.7	78.6	80.7	87.5	98.6	106.7	102.4	76.0	72.2	96.0	94.1	92.3	67.9	73.0	88.6	86.1	72.7	174.8

	Project Impact	Case No.	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour ($\mu g/m^3$)	91.3	3	1995	1,300	1,300	7.0	7.0
HSH, 24-Hour ($\mu g/m^3$)	22.9	5	1995	260	365	8.8	6.3
Annual ($\mu g/m^3$)	2.0	3	1996	60	80	3.3	2.5
NO_2							
Annual ($\mu g/m^3$)	3.3	3	1996	100	100	3.3	3.3
PM_{10}							
HSH, 24-Hour ($\mu g/m^3$)	58.9	12	1995	150	150	39.3	39.3
Annual ($\mu g/m^3$)	5.5	12	1996	50	50	11.1	11.1
CO							
HSH, 1-Hour ($\mu g/m^3$)	261.5	3	1992	40,000	40,000	0.7	0.7
HSH, 8-Hour ($\mu g/m^3$)	174.8	7	1995	10,000	10,000	1.7	1.7

Source: ECT, 2001.

APPENDIX A

APPLICATION FOR AIR PERMIT—

TITLE V SOURCE

Department of
Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Tampa Electric Company**	
2. Site Name: **F.J. Gannon/Bayside Power Station**	
3. Facility Identification Number: **0570040** [ ] Unknown	
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 Permitted Facility? [✔] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Patrick Shell** **Manager, Generation Projects**
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 – 5210** Fax: **(813) 641-5081**

Application Processing Information (DEP Use)

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

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number: ____________________

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

Current construction permit number: ____________________

Operation permit number to be revised: ____________________

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

Operation permit number to be revised/corrected: ____________________

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

Operation permit number to be revised: ____________________

Reason for revision: ____________________

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Karen Sheffield, General Manager – Bayside Station**
2.	Application Contact Mailing Address: Organization/Firm: **Tampa Electric Company** Street Address: **Port Sutton Road** City: **Tampa** State: **FL** Zip Code: **33619**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(813) 641-5400** Fax: **(813) 641-5418**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [✔], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Karen A. Sheffield 6/21/01 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address: Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **FL** Zip Code: **32606**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 332-0444** Fax: **(352) 332-6722**

4. Professional Engineer Statement:

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

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

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

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

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

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

Thomas W. Davis
Signature

6/15/01
Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
026	Bayside Combustion Turbine Unit No. 3-A	AC1A	$7,500
027	Bayside Combustion Turbine Unit No. 3-B	AC1A	N/A
028	Bayside Combustion Turbine Unit No. 4-A	AC1A	N/A
029	Bayside Combustion Turbine Unit No. 4-B	AC1A	N/A

Application Processing Fee

Check one: [✔] Attached - Amount: $ **7,500** [ ] Not Applicable

Note: PSD review fee provided per Rule 62-4.050(4)(a)1., F.A.C.

Construction/Modification Information

1. Description of Proposed Project or Alterations: **TEC is proposing to repower Units 3 and 4 at the F.J. Gannon Station by installing four General Electric (GE) 7FA combustion turbine (CT)/heat recovery steam generator (HRSG) units that will operate in conjunction with the existing Units 3 and 4 steam turbines (STs). The four new CT/HRSG units will be grouped into two units designated as Bayside Power Station (Bayside) Units 3 and 4. Bayside Units 3 and 4 will repower F.J. Gannon Station Units 3 and 4, respectively. Bayside Unit 3 will include two CT/HRSGs designated as CT-3A and CT-3B. Bayside Unit 4 will include two CT/HRSGs designated as CT-4A and CT-4B. The CTs will be fired exclusively with pipeline quality natural gas. The new combined-cycle CT/HRSGs will operate at an annual capacity factor of up to 100 percent.**
2. Projected or Actual Date of Commencement of Construction: **May 2002**
3. Projected Date of Completion of Construction: **May 2004**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **360.00**	North (km): **3,087.50**	
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 (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Adriano Alcoz, 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. Facility Contact Telephone Numbers: Telephone: **(813) 228-1111, Ext. 35095** Fax: **(813) 641-5566**

Facility Regulatory Classifications

Check all that apply:

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

List of Applicable Regulations

Previously submitted – see Title V permit application.	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NOX	**A**	**N/A**	**N/A**	**N/A**	
SO2	**A**	**N/A**	**N/A**	**N/A**	
CO	**A**	**N/A**	**N/A**	**N/A**	
PM10	**A**	**N/A**	**N/A**	**N/A**	
PM	**A**	**N/A**	**N/A**	**N/A**	
SAM	**A**	**N/A**	**N/A**	**N/A**	
VOC	**A**	**N/A**	**N/A**	**N/A**	
PB	**B**	**N/A**	**N/A**	**N/A**	
HAPS	**A**	**N/A**	**N/A**	**N/A**	
H106 (HCl)	**A**	**N/A**	**N/A**	**N/A**	
H107 (HF)	**A**	**N/A**	**N/A**	**N/A**	

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [ ] Attached, Document ID: [ ] Not Applicable [✔] Waiver Requested	
2. Facility Plot Plan: [ ] Attached, Document ID: [ ] Not Applicable [✔] Waiver Requested	
3. Process Flow Diagram(s): [ ] Attached, Document ID: [ ] Not Applicable [✔] Waiver Requested	
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID: [ ] Not Applicable [✔] Waiver Requested	
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [ ] Not Applicable [✔] Waiver Requested	
6. Supplemental Information for Construction Permit Application: [✔] Attached, Document ID: [ ] Not Applicable **Air Construction Permit Application**	
7. Supplemental Requirements Comment: **Items 1, 2, 3, 4, and 5 above previously submitted - see F.J. Gannon Station Title V permit application.**	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

Items 8. through 15. above previously submitted – see F.J. Gannon Station Title V permit application.

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Emission unit consists of one General Electric (GE) 7241 FA combined-cycle combustion turbine generator (CT) having a nominal rating of 170 megawatts (MW). The CT will be fired exclusively with pipeline quality natural gas.

4. Emissions Unit Identification Number: [✔] No ID
ID: **026 (CT 3-A)** [ ] ID Unknown

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

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

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **NO_x Controls** **Dry low-NO_x combustors** **Selective Catalytic Reduction (SCR)**
2. Control Device or Method Code(s): **025 (dry low-NO_x combustors)** **065 (catalytic reduction)**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **PG7241(FA)**
2. Generator Nameplate Rating: **170** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	**1,841.7 (HHV)**	mmBtu/hr		
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input is higher heating value (HHV) at 100 percent load, 59°F, operating conditions. Heat input will vary with load and ambient temperature.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **CT 3-A**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

N/A

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

N/A

5. Discharge Type Code: **V**	6. Stack Height: **150** feet	7. Exit Diameter: **19.0** feet
8. Exit Temperature: **212** °F	9. Actual Volumetric Flow Rate: **1,018,786** acfm	10. Water Vapor: %

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

13. Emission Point UTM Coordinates:

Zone: East (km): North (km):

14. Emission Point Comment (limit to 200 characters):

Stack temperature and flow rate are at 100 percent load and 59°F ambient temperature operating conditions. Stack temperature and flow rate will vary with load and ambient temperature.

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

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.934**	5. Maximum Annual Rate: **16,941.8**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,025**
10. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents higher heating value (HHV).**		

Segment Description and Rate: Segment ___ of ___

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
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 (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – NOX	**025**	**065**	**EL**
2 – CO			**EL**
3 – PM			**EL**
4 – PM10			**EL**
5 – SO2			**EL**
6 – SAM			**EL**
7 – VOC			**EL**

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **24.7** lb/hour **101.2** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **24.7 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 23.1 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvd @ 15% O_2, 24-Hour Block Average**	4. Equivalent Allowable Emissions: **23.1** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 7E (initial), NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP/EPA Consent Agreement.** **Field 4 (23.1 lb/hr) equivalent allowable emissions is at a CT inlet air temperature of 59° F.** **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **31.1** lb/hour **125.7** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **31.1 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 28.7 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **7.8 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **28.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Field 4 (28.7 lb/hr) equivalent allowable emissions is at a CT inlet air temperature of 59° F.**	

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

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9.0 ppmvd, 24-Hour Block Average**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **CO CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Field 3 (9.0 ppmvd) is corrected to 15% O_2.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **20.5** lb/hour **88.9** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **20.5 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 20.3 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **PM emissions data represents "front- and back-half" particulate matter as measured by EPA Reference Methods 201 and 202. PM and PM_{10} emissions are assumed to be equal.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **20.5** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **20.5** lb/hour **88.9** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **20.5 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 20.3 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **PM emissions data represents "front- and back-half" particulate matter as measured by EPA Reference Methods 201 and 202. PM and PM_{10} emissions are assumed to be equal.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **20.5** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.1** lb/hour **45.1** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **11.1 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**

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

(2.0 gr S/100 scf) x (1.934 x 10^6 ft^3/hr) x (1 lb S/7,000 gr S) x (2 lb SO_2/lb S) = 11.1 lb/hr SO_2

Annual emissions based on 10.3 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **11.1** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
Fuel analysis for sulfur content

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

Unit is also subject to less stringent fuel sulfur limits of 40 CFR Part 60, Subpart GG (NSPS).

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.0** lb/hour **8.3** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **2.0 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 1.9 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **2.0 gr S/100 scf**	4. Equivalent Allowable Emissions: **2.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis for sulfur content**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.0** lb/hour **12.3** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **3.0 lb/hr** Reference: **Sargent & Lundy**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 18°F. Annual emissions based on 2.8 lb/hr (100 percent load and 59°F) for 8,760 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Clean Fuel and Good Operating Practices**	4. Equivalent Allowable Emissions: **3.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **N/A**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [✔] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment (limit to 200 characters):	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

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

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **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: CO_2	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 (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).** **Specific CEMS information will be provided to FDEP when available.**	

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

Supplemental Requirements

1. Process Flow Diagram [✔] Attached, Document ID: **Fig. 2-4** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [✔] Attached, Document ID: **Att. A-2** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [✔] Attached, Document ID: **Att. B** [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities **To be provided** [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [ ] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application **See permit application** [ ] Attached, Document ID:________ [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
[ ] Attached, Document ID:________ [ ] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
[ ] Attached, Document ID:________ [ ] Not Applicable

13. Identification of Additional Applicable Requirements
[ ] Attached, Document ID:________ [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
[ ] Attached, Document ID:________ [ ] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

[ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID:________

[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
Attached, Document ID:________

[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
Attached, Document ID:________

[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
Attached, Document ID:________

[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
Attached, Document ID:________

[ ] Not Applicable

Above items previously submitted, see F.J. Gannon Station Title V permit application.

NOTE:

EMISSION UNITS CT-3A, CT-3B, CT-4A, AND CT-4B ARE IDENTICAL UNITS.

SECTION III. EMISSIONS UNIT INFORMATION PROVIDED FOR EU 026 (CT-3A) IS ALSO APPLICABLE TO EU 027 (CT-3B), EU 028 (CT-4A), AND EU 029 (CT-4B).

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

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-4B	General recordkeeping and reporting requirements.
Performance Tests	§60.8		CT 3A-4B	Conduct performance tests as required by EPA or FDEP. **(potential future requirement)**
Compliance with Standards	§60.11(a) thru (d), and (f)		CT 3A-4B	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		CT 3A-4B	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-4B	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		CT 3A-4B	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-4B	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-4B	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-4B	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-4B	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	§60.335		CT 3A-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CT 3A-4B	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-4B	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		CT 3A-4B	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CT 3A-4B	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-4B	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-4B	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-4B	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		CT 3A-4B	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CT 3A-4B	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CT 3A-4B	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-4B	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-4B	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-4B	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CT 3A-4B	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and (c)		CT 3A-4B	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CT 3A-4B	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CT 3A-4B	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CT 3A-4B	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CT 3A-4B	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CT 3A-4B	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-4B	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CT 3A-4B	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CT 3A-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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 appliances. All such activities will be performed by independent parties in compliance with §82.154 prohibitions.
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors will maintain, service, repair, and dispose of any appliances in compliance with §82.156 required practices.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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-4B	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 (HHV)	1,020 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, 2001.

APPENDIX B

NITROGEN OXIDES
CONTROL SYSTEM DESCRIPTION

NITROGEN OXIDES CONTROL SYSTEM DESCRIPTIONS

A. Selective Catalytic Reduction

Selective catalytic reduction (SCR) technology will be used to control NO_x emissions from Bayside Units 3 and 4. SCR reduces NO_x emissions by reacting ammonia (NH_3) with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. NH_3 is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (2)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (1) and (2) will not proceed. At temperatures exceeding the optimal range, oxidation of NH_3 will take place resulting in an increase in NO_x emissions. Due to these temperature constraints, the SCR catalyst modules will be located in the appropriate section of the HRSGs where temperatures are suitable for proper SCR operation.

A NH_3 injection grid will be located in the HRSG downstream of the high pressure steam drum and upstream of the SCR catalyst modules. This injection grid will be utilized to inject anhydrous ammonia into the CT exhaust stream. The NH_3 and NO_x (i.e., NO and NO_2) in the exhaust stream will then be adsorbed on the surface of the SCR catalyst and react catalytically to form N_2 and H_2O per reactions (1) and (2) above. The N_2 and H_2O formed is subsequently desorbed and discharged to the atmosphere with the CT exhaust stream.

The reaction of NO_x with NH_3 theoretically requires a 1:1 molar ratio. NH_3/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, NH_3/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted NH_3 (ammonia slip) emissions. The Bayside Units 3 and 4 SCR control systems are designed to achieve a target ammonia slip rate of no more than 5.0 ppmvd at 15% O_2. If the ammonia slip concentration exceeds 5.0 ppmvd at 15% O_2, additional ammonia slip testing will be taken in accordance with the additional ammonia slip testing requirements specified in Condition No. 24. of FDEP Project No. 0570040-013-AC, Air Permit No. PSD-FL-301 issued for Bayside Units 1 and 2. Corrective action will be taken prior to the ammonia slip exceeding 7.0 ppmvd at 15% O_2 in accordance this permit condition for Bayside Units 1 and 2.

APPENDIX C

EMISSION RATE CALCULATIONS

Table 1. Bayside Station - Units 3 and 4
Operating Scenarios - General Electric PG7241 (FA) CTs

Case	Ambient Temperature (oF)	Load (%)	CT 3A-3B CT 4A-4B Combined Cycle	Annual Profile (hr/yr)	Evaporative Cooling	Natural Gas Firing
1	18	100	X			X
2	18	75	X			X
3	18	50	X			X
4	59	100	X	8,760 (Gas)		X
5	59	75	X			X
6	59	50	X			X
7	72	100	X		X	X
8	72	75	X			X
9	72	50	X			X
10	93	100	X		X	X
11	93	75	X			X
12	93	50	X			X

Sources: TEC, 2001.
ECT, 2001.

Ta[illegible] Bayside Station - Units 3 and 4
Hourly Emission Rates - Natural Gas-Firing
General Electric 7FA CTs (Per CT)

Temp. (°F)	Case	Load (%)	PM/PM_{10}[a]		SO_2[b]		H_2SO_4[c]		Lead[d]	
			(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
18	1	100	20.5	2.58	11.1	1.39	2.0	0.26	0.0310	0.00390
	2	75	20.0	2.52	9.0	1.13	1.6	0.21	0.0251	0.00317
	3	50	19.6	2.47	7.2	0.91	1.3	0.17	0.0202	0.00254
59	4	100	20.3	2.56	10.3	1.30	1.9	0.24	0.0289	0.00364
	5	75	19.9	2.51	8.4	1.06	1.5	0.20	0.0236	0.00298
	6	50	19.5	2.46	6.8	0.85	1.2	0.16	0.0189	0.00239
72	7	100	20.3	2.56	10.1	1.27	1.9	0.23	0.0283	0.00356
	8	75	19.8	2.49	8.2	1.03	1.5	0.19	0.0230	0.00290
	9	50	19.5	2.46	6.6	0.83	1.2	0.15	0.0184	0.00232
93	10	100	20.2	2.55	9.8	1.23	1.8	0.23	0.0274	0.00345
	11	75	19.7	2.48	7.8	0.98	1.4	0.18	0.0218	0.00275
	12	50	19.4	2.44	6.2	0.79	1.1	0.14	0.0175	0.00220
		Maximums	**20.5**	**2.58**	**11.1**	**1.39**	**2.0**	**0.26**	**0.0310**	**0.00390**

Temp. (°F)	Case	Load (%)	NO_x			CO			VOC		
			(ppmvd)[e]	(lb/hr)	(g/sec)	(ppmvd)[e]	(lb/hr)	(g/sec)	(ppmvd)[e][f]	(lb/hr)[g]	(g/sec)
18	1	100	3.5	24.7	3.11	7.2	31.1	3.92	1.2	3.0	0.38
	2	75	3.5	19.9	2.51	7.1	24.6	3.10	1.2	2.4	0.30
	3	50	3.5	15.8	1.99	7.4	20.4	2.57	1.3	2.0	0.25
59	4	100	3.5	23.1	2.91	7.2	28.7	3.62	1.2	2.8	0.35
	5	75	3.5	18.7	2.36	7.2	23.5	2.96	1.2	2.3	0.29
	6	50	3.5	14.8	1.86	7.6	19.5	2.46	1.3	1.9	0.24
72	7	100	3.5	22.6	2.85	7.1	27.8	3.50	1.2	2.7	0.34
	8	75	3.5	18.2	2.29	7.2	22.8	2.87	1.2	2.2	0.28
	9	50	3.5	14.4	1.81	7.6	19.1	2.41	1.3	1.9	0.24
93	10	100	3.5	21.9	2.76	7.1	26.9	3.39	1.2	2.7	0.34
	11	75	3.5	17.2	2.17	7.3	21.9	2.76	1.3	2.2	0.28
	12	50	3.5	13.7	1.73	7.8	18.6	2.34	1.3	1.8	0.23
		Maximums	**3.5**	**24.7**	**3.11**	**7.8**	**31.1**	**3.92**	**1.3**	**3.0**	**0.38**

[a] As measured by EPA Reference Methods 201 and 202.
[b] Based on natural gas sulfur content of 2.0 gr/100 ft^3.
[c] Based on 8.0% conversion of fuel S to SO_3 (CT), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.
[d] AP-42, EPA, May 1998 - Draft.
[e] *Corrected to 15% O_2.*
[f] Non-methane, non-ethane.
[g] Expressed as methane.

Sources: ECT, 2001.
S&L, 2001.

HAZARDOUS AIR POLLUTANT EMISSION FACTORS

Section 3.1 of AP-42, Stationary Gas Turbines, was revised in April 2000 to include natural gas-fired combustion turbine (CT) emission factors for eleven hazardous air pollutants (HAPs), including formaldehyde and toluene. The April 2000 AP-42 formaldehyde and toluene emission factors for natural gas-fired CTs are 7.1×10^{-4} and 1.3×10^{-4} lb/10^6 Btu, respectively.

As stated in the introduction to AP-42, the emission factors in AP-42 are "simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average)". Accordingly, the emission factors in AP-42 are generally appropriate for use in making areawide emission inventories. Because the AP-42 emission factors represent a source category population average, the factors do not necessarily reflect the emission rates for any particular member of that source category population.

In the case of the formaldehyde emission factor for natural gas-fired CTs, the April 2000 AP-42 emission factor is based on the average of 22 CT source tests. The CTs in the 22 source test database include small CTs (9 of the 22 CTs tested, or 40% of all units tested, had a rating of less than 15 MW), aircraft-derivative CTs (5 of the 22 CTs, or 23% of all units tested, were GE LM series aircraft-derivative CTs), and frame-type CTs. The largest CT of the 22 units tested was a GE Frame 7E unit with a rating of 87.8 MW. The average rating of the 22 CTs tested is 30.2 MW. The majority of the CTs tested were equipped with wet (water or steam) injection to control NO_x emissions.

The AP-42 CT test database shows considerable variability in formaldehyde emission factors. The maximum formaldehyde emission factor (5.61×10^{-3} lb/10^6 Btu) is 2,538 times higher than the minimum factor (2.21×10^{-6} lb/10^6 Btu). Six of the 22 test series include runs for which there were no detectable emissions of formaldehyde.

The CTs proposed for Bayside Units 3 and 4 are GE Frame 7FA units each rated at a nominal 170 MW. During natural gas-firing, dry low-NO_x (DLN) combustor and SCR control technology will be employed to control NO_x emissions. Accordingly, the average April 2000 AP-42 formaldehyde emission factor for natural gas-fired CTs is not considered applicable to the GE 7FA CT. The GE 7FA CT is 5.5 times larger (i.e., has a rating of 170 vs. 30.6 MW) than the average CT included in the AP-42 CT database and is equipped with DLN and SCR control technology.

Evaluation of the AP-42 CT formaldehyde source test database shows that six of the units tested were large, frame-type CTs. Emission factors for these six CTs were averaged to develop a formaldehyde emission factor which is considered to be more representative of the GE 7FA units. This average factor for frame-type CTs, 1.14×10^{-4} lb/10^6 Btu, was used to estimate emissions of formaldehyde for Bayside Units 3 and 4.

A similar analysis was conducted with respect to the April 2000 AP-42 toluene emission factor for natural gas-fired CTs. The April 2000 AP-42 toluene emission factor is based on the average of 7 CT source tests. The CTs in the 7 source test database include small CTs (3 of the 7 CTs tested, or 43% of all units tested, had a rating of less than 15 MW), aircraft-derivative CTs (2 of the 7 CTs, or 29% of all units tested, were GE LM series aircraft-derivative CTs), and frame-type CTs. The largest CT of the 7 units tested was a GE Frame 7 unit with a rating of 75 MW. The average rating of the 7 CTs tested is 26.6 MW. The majority of the CTs tested were equipped with wet (water or steam) injection to control NO_x emissions.

The AP-42 CT test database also shows variability in toluene emission factors. The maximum toluene emission factor (7.10×10^{-4} lb/10^6 Btu) is 67.6 times higher than the minimum factor (1.05×10^{-5} lb/10^6 Btu). Two of the 7 test series include runs for which there were no detectable emissions of toluene.

Evaluation of the AP-42 CT toluene source test database shows that two of the units tested were large, frame-type CTs. Emission factors for these two CTs were averaged to develop a toluene emission factor which is considered to be more representative of the GE 7FA units. This average factor for frame-type CTs, 6.80×10^{-5} lb/10^6 Btu, was used to estimate emissions of toluene for Bayside Units 3 and 4.

Average emission factors for frame-type CTs were developed for the remaining listed HAPs for natural gas-fired CTs using the same methodology as described above for formaldehyde and toluene.

Table 3. Bayside Station - Units 3 and 4
Natural Gas-Firing: Hazardous Air Pollutants

Parameter	Units	Case		
		100% - 18 °F	100% - 59 °F	100 % - 93 °F
Maximum Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,973.0	1,841.7	1,747.1
Maximum Annual Hours:	hrs/yr	N/A	8,760	N/A

Pollutant	Emission Factor [(a)(b)] (lb/10^6 Btu)	Emission Rates (Per CT)				Unit 3 Annual (ton/yr)	Unit 4 Annual (ton/yr)
		18 °F (lb/hr)	59 °F (lb/hr)	93 °F (lb/hr)	Annual (ton/yr)		
1,3-Butadiene	6.05E-08	0.00012	0.00011	0.00011	0.00049	0.0010	0.0010
Acetaldehyde	4.31E-05	0.085	0.079	0.075	0.348	0.70	0.695
Acrolein	5.60E-06	0.011	0.010	0.010	0.045	0.09	0.090
Benzene	1.83E-05	0.036	0.034	0.032	0.148	0.30	0.295
Ethylbenzene	2.28E-05	0.045	0.042	0.040	0.184	0.37	0.368
Formaldehyde	1.14E-04	0.225	0.210	0.199	0.920	1.84	1.839
Mercury	7.80E-10	0.0000015	0.0000014	0.0000014	0.0000063	0.000013	0.000013
Naphthalene	6.33E-07	0.0012	0.0012	0.0011	0.0051	0.010	0.010
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.0009	0.0009	0.0008	0.0038	0.008	0.008
Propylene Oxide	2.86E-05	0.056	0.053	0.050	0.231	0.461	0.461
Toluene	6.80E-05	0.134	0.125	0.119	0.549	1.097	1.097
Xylene	6.51E-05	0.128	0.120	0.114	0.525	1.050	1.050
Maximum Individual HAP		0.225	0.210	0.199	0.920	1.839	1.839
Total HAPs		0.723	0.675	0.641	2.958	5.915	5.915

[(a)] - All emission factors except mercury, Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.

[(b)] - Mercury emision factor, Florida Coordinating Group (FCG), 1995.

Source: ECT, 2001.

Table 4A. Bayside Station
Annual Emission Rates - Unit 3

No. of CTs	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
2	4	8,760	46.2	202.4	57.4	251.4	5.60	24.5
		Totals	**N/A**	**202.4**	**N/A**	**251.4**	**N/A**	**24.5**

No. of CTs	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)
2	4	8,760	40.6	177.8	20.6	90.4	3.8	16.6	0.058	0.25
		Totals	**N/A**	**177.8**	**N/A**	**90.4**	**N/A**	**16.6**	**N/A**	0.25

1. Three CTs operating with natural gas-firing for 8,760 hours/year at base load (Case 4).
2. Natural gas SO_2 rates based on natural gas sulfur content of 2.0 gr/100 ft^3.
3. Natural gas H_2SO_4 rates based on 8.0% conversion of fuel S to SO_3 (CT), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

Table 4B. Bayside Station
Annual Emission Rates - Unit 4

No. of CTs	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
2	4	8,760	46.2	202.4	57.4	251.4	5.60	24.5
		Totals	**N/A**	**202.4**	**N/A**	**251.4**	**N/A**	**24.5**

No. of CTs	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)
2	4	8,760	40.6	177.8	20.6	90.4	3.8	16.6	0.058	0.25
		Totals	**N/A**	**177.8**	**N/A**	**90.4**	**N/A**	**16.6**	**N/A**	**0.25**

1. Four CTs operating with natural gas-firing for 8,760 hours/year at base load (Case 4).
2. Natural gas SO_2 rates based on natural gas sulfur content of 2.0 gr/100 ft^3.
3. Natural gas H_2SO_4 rates based on 8.0% conversion of fuel S to SO_3 (CT), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

Table 4C. Bayside Station
Annual Emission Rates - Units 3 and 4

No. of CTs	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
4	4	8,760	92.4	404.7	114.8	502.8	11.20	49.1
		Totals	**N/A**	**404.7**	**N/A**	**502.8**	**N/A**	**49.1**

No. of CTs	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)
4	4	8,760	81.2	355.7	41.3	180.8	7.6	33.2	0.116	0.51
		Totals	**N/A**	**355.7**	**N/A**	**180.8**	**N/A**	**33.2**	**N/A**	**0.51**

1. Seven CTs operating with natural gas-firing for 8,760 hours/year at base load (Case 4).
2. Natural gas SO_2 rates based on natural gas sulfur content of 2.0 gr/100 ft^3.
3. Natural gas H_2SO_4 rates based on 8.0% conversion of fuel S to SO_3 (CT), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

Table 5. Bayside Station - Units 3 and 4
Annual Hazardous Air Pollutants Emission Rates

Pollutant	Unit 3 Emissions (ton/yr)	Unit 4 Emissions (ton/yr)	Units 3 & 4 Emissions (ton/yr)
1,3-Butadiene	0.0010	0.0010	0.0020
Acetaldehyde	0.695	0.695	1.391
Acrolein	0.090	0.090	0.181
Benzene	0.295	0.295	0.590
Ethylbenzene	0.368	0.368	0.736
Formaldehyde	1.839	1.839	3.678
Mercury	0.000013	0.000013	0.000025
Naphthalene	0.010	0.010	0.020
Polycyclic Aromatic Hydrocarbons	0.008	0.008	0.015
Propylene Oxide	0.461	0.461	0.923
Toluene	1.097	1.097	2.194
Xylene	1.050	1.050	2.101
Maximum Individual HAP	1.839	1.839	3.678
Total HAPs	5.915	5.915	11.831

Source: ECT, 2001.

Table 6. Bayside Station - Units 3 and 4
Stack Parameters (Per CT/HRSG)
Natural Gas-Firing

Stack Height:	150.0	ft	Stack Area:	283.5	ft^2
	45.7	m		26.3	m^2
Stack Diameter:	19.0	ft			
	5.8	m			

Case	Temperature		Flow Rate (actual)		Velocity	
	(°F)	(K)	(ft^3/min)	(m^3/min)	(ft/sec)	(m/s)
1	233	385	1,128,021	31,942	66.3	20.2
2	215	375	869,018	24,608	51.1	15.6
3	201	367	705,450	19,976	41.5	12.6
4	212	373	1,018,786	28,849	59.9	18.3
5	212	373	832,897	23,585	49.0	14.9
6	211	373	689,171	19,515	40.5	12.3
7	215	375	1,003,134	28,406	59.0	18.0
8	214	374	819,987	23,219	48.2	14.7
9	213	374	682,862	19,337	40.1	12.2
10	216	375	980,050	27,752	57.6	17.6
11	215	375	790,282	22,378	46.5	14.2
12	213	374	667,237	18,894	39.2	12.0

Sources: ECT, 2001.
S&L, 2001.

Table 7. Bayside Station Units 3 and 4
Fuel Flow Data - General Electric PG7241(FA); Per CTG

Natural Gas-Firing

	100 % Load				75 % Load				50 % Load			
	18 °F	59 °F	72 °F	93 °F	18 °F	59 °F	72 °F	93 °F	18 °F	59 °F	72 °F	93 °F
Case	1	4	7	10	2	5	8	11	3	6	9	12
Heat Input - LHV[1] (MMBtu/hr)	1,777.8	1,659.5	1,623.4	1,574.3	1,442.9	1,356.5	1,320.8	1,252.1	1,157.5	1,087.9	1,057.0	1,003.7
Heat Input - HHV (MMBtu/hr)	1,973.0	1,841.7	1,801.6	1,747.1	1,601.3	1,505.4	1,465.7	1,389.6	1,284.6	1,207.3	1,173.1	1,113.9
Fuel Rate[2] (lb/hr)	85,136	79,471	77,741	75,392	69,097	64,959	63,249	59,963	55,433	52,097	50,620	48,067
Fuel Rate[3] (10^6 ft^3/hr)	1.934	1.806	1.766	1.713	1.570	1.476	1.437	1.362	1.260	1.184	1.150	1.092
Fuel Rate (lb/sec)	23.649	22.075	21.595	20.942	19.194	18.044	17.569	16.656	15.398	14.471	14.061	13.352

[1] Includes a 3.5% margin to account for heat rate degradation over time.
[2] Natural gas heat content of 20,882 Btu/lb (LHV).
[3] Natural gas density of 0.0443 lb/ft^3.

Sources: ECT, 2001.
S&L, 2001.
TEC, 2001.

Table 8. Bayside Station Units 3 and 4
General Electric PG7241(FA) CT
NSPS GG NO_x Limit

Fuel	PG7241(FA) Gas Turbine ISO Heat Rate (LHV)		FBN F	NO_x Std (ppmvd)
	(Btu/kw-hr)	(kj/w-hr)		
Natural Gas	9,465	9.986	0.0	108.2

Sources: ECT, 2001.
GE, 2001.

APPENDIX D
PSD NETTING ANALYSIS

Bayside Units 3 and 4 PSD Netting Analysis

The procedures for determining applicability of the PSD NSR permitting program to modifications planned at existing major Florida facilities are specified in Rule 62-212.400(2)(d)4., F.A.C. Because the existing F.J. Gannon Station is a major facility (i.e., has potential emissions of 100 tpy or more of an air pollutant subject to regulation under Chapter 403, Florida Statutes) that would be subject to PSD preconstruction review if it were itself a proposed new facility (i.e., has potential emissions of 100 tpy or more of a pollutant regulated under the Clean Air Act and is located in an attainment area), modifications to the existing F.J. Gannon Station which result in a *significant net emissions increase* of any pollutant regulated under the Clean Air Act are subject to PSD NSR.

The term "significant net emission increase" is defined by Rule 62-212.400(2)(e), F.A.C. For each regulated pollutant, the net emission increase for a modification project is equal to the sum of the increases in emissions associated with the proposed project plus all facility-wide creditable, contemporaneous emission increases minus all facility-wide creditable, contemporaneous emission decreases. If this net emissions increase is equal to or greater than the applicable Table 212.400-2, F.A.C. Regulated Pollutants—Significant Emission Rates, then the net emission increase is considered to be "significant" and the modification will be subject to PSD NSR for that particular regulated pollutant.

In accordance with Rule 62-212.400(2)(e)3., F.A.C., the "contemporaneous" period for a modification project begins five years prior to the date of submittal of a complete permit application and ends when the new or modified emission units are estimated to begin operation.

In accordance with Rule 62-212.400(2)(e)4., F.A.C., contemporaneous emission increases and decreases are "creditable" if:

(1) the emission increase or decrease will affect PSD increment consumption; i.e., will consume or expand the available increment;

(2) The emission increase or decrease was not previously considered in the issuance of a PSD NSR permit (to avoid "double counting"); and

(3) The FDEP has not relied on the emission increase or decrease in attainment or reasonable further progress demonstrations.

Contemporaneous emission increases and decreases are based on *actual* emission rates. The term "actual emissions" is defined by Rule 62-210.200(12), F.A.C. For new emission units, including new electric utility steam generating units, actual emissions are equal to potential emissions. For changes to existing emission units, actual emissions are generally the actual average emission rates, in tpy, for the two year period preceding the change and which are representative of normal operations. The Department may allow the use of a different time period if it is determined that the other time period is more representative of the normal operation of an emissions unit.

For emission decreases, the old level of actual or allowable emissions (whichever is lower) must be greater than the new level of actual emissions. The actual emission decrease must also take place on or before the date that emissions from the modification project first occur and must be federally enforceable on and after the date the Department issues a construction permit for the modification project.

For Bayside Units 3 and 4, the contemporaneous period is projected to begin in March 1996 and end in June 2005. Creditable emission decreases that will occur within this contemporaneous period consist of the actual emissions associated with the cessation of coal-fired operations of F.J. Gannon Station Units 3 and 4. Creditable emission increases consist of those associated with Bayside Units 3 and 4. Emission decreases and increases associated with the Bayside Units 1 and 2 Repowering Project (i.e., decreases associated with the cessation of coal-fired operations of F.J. Gannon Station Units 5 and 6 and increases associated with Bayside Units 1 and 2) are not creditable because they have been relied on in the issuance of the PSD NSR permit for Bayside Units 1 and 2. There are no other creditable emission increases that have occurred or will occur at the F.J. Gannon Station during the March 1996 through June 2005 contemporaneous period.

Summaries of historical, actual emission rates for F.J. Gannon Station Units 3 and 4 for the 1996 – 2000 five year period are provided on Tables 1 and 2, respectively.

Table 3 provides an analysis of PSD NSR applicability for Bayside Units 3 and 4. Contemporaneous, creditable emission decreases were determined based on the average actual emissions for F.J. Gannon Station Units 3 and 4 for the 1999/2000 two-year period. These actual emission rates reflect the retroactive application of NO_x, SO_2, and PM BACT in accordance with provisions of the EPA/TEC Consent Decree. The net emission rate changes due to the increase in potential emissions for Bayside Units 3 and 4, minus the two-year average actual emissions for F.J. Gannon Station Units 3 and 4 are all below the applicable Table 212.400-2, F.A.C. Regulated Pollutants—Significant Emission Rates with the exception of CO and PM/PM_{10}. For most regulated pollutants, there will be a substantial reduction in actual emissions; e.g., approximately 570 tpy for SO_2 and NO_x. Accordingly, Bayside Units 3 and 4 are subject to PSD NSR for CO and PM/PM_{10} only.

Table 1. Bayside Station Units 3 and 4
Netting Analysis - F.J. Gannnon Station Unit 3 Historical Emissions

	1996	1997	1998	1999	2000	96-00, 5 Yr Avg	99,00 Avg
Coal Usage (tons)	298,202	502,172	441,838	431,164	474,944	429,664	453,054
Wt % Ash	6.60	6.88	6.79	6.87	7.09	6.85	6.98
Heat Content (10^6 Btu/ton)	23.31	20.06	19.19	21.00	20.00	20.71	20.50
Wt % S	1.12	1.15	0.87	0.95	0.85	0.99	0.90
Oil Usage (10^3 gal)	311.0	639.9	599.0	397.0	10,156.9	2,420.7	5,277
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.000
Wt % S	0.30	0.15	0.28	0.41	0.42	0.31	0.42
Total Heat Input (10^6 Btu/yr)	6,994,776	10,161,863	8,561,862	9,109,230	10,900,532	9,145,653	10,004,881
NO_x [(a)]	349.7	508.1	428.1	455.5	545.0	457.3	500.2
CO AOR	90.0	153.0	111.0	108.8	119.8	116.5	114.3
SO_2 [(b)]	320.3	488.6	372.9	372.9	367.5	384.4	370.2
H_2SO_4 [(c)] AP-42 (1998)	18.7	32.3	21.6	23.0	25.9	24.3	24.4
PM_{10} [(d)]	35.0	50.8	42.8	45.5	54.5	45.7	50.0
PM [(d)]	35.0	50.8	42.8	45.5	54.5	45.7	50.0
Pb AOR	2.0	3.3	2.9	2.9	0.1	2.2	1.5
VOC AP-42 (1998)	16.4	27.7	24.4	23.8	27.1	23.9	25.4

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Table 2. Bayside Station Units 3 and 4
Netting Analysis - F.J. Gannnon Station Unit 4 Historical Emissions

	1996	1997	1998	1999	2000	96-00, 5 Yr Avg	99,00 Avg
Coal Usage (tons)	486,874	474,906	486,831	408,955	461,418	463,797	435,187
Wt % Ash	6.75	6.85	6.79	6.95	7.13	6.89	7.04
Heat Content (10^6 Btu/ton)	22.35	20.87	20.04	20.00	20.00	20.65	20.00
Wt % S	1.08	1.04	0.87	0.94	0.86	0.96	0.90
Oil Usage (10^3 gal)	311.0	576.9	599.0	397.0	10,156.9	2,408.1	5,277
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.219	138.000
Wt % S	0.30	0.15	0.28	0.41	0.41	0.31	0.41
Total Heat Input (10^6 Btu/yr)	10,924,725	9,990,887	9,839,084	8,233,886	10,630,012	9,923,719	9,431,949
NO_x (a)	546.2	499.5	492.0	411.7	531.5	496.2	471.6
CO AOR	147.0	143.0	123.0	103.2	116.4	126.5	109.8
SO_2 (b)	492.8	519.2	477.7	373.5	391.6	450.9	382.5
H_2SO_4 (c) AP-42 (1998)	29.4	27.6	23.7	21.6	25.4	25.5	23.5
PM_{10} (d)	54.6	50.0	49.2	41.2	53.2	49.6	47.2
PM (d)	54.6	50.0	49.2	41.2	53.2	49.6	47.2
Pb AOR	3.2	3.2	3.2	2.7	0.1	2.5	1.4
VOC AP-42 (1998)	26.8	26.2	26.8	22.5	26.4	25.7	24.5

(a) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(b) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 35% to reflect retroactive BACT.
(d) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

Table 3. Bayside Station
Bayside Units 3 & 4/F.J. Gannon Units 3 & 4 Emissions Netting Analysis

	Units 3 & 4 (tpy)					Unit 3 2 Yr [a] Avg	Unit 4 2 Yr [a] Avg	Total 2 Yr [a] Avg	CT 3A-4B (tpy)	Net Change (tpy)	PSD Threshold (tpy)	PSD Review (Y/N)
	1996	1997	1998	1999	2000							
Coal Usage (tons)	785,076	977,078	928,669	840,119	936,362	453,054	435,187	888,241	N/A	N/A	N/A	N/A
Wt % Ash	6.68	6.87	6.79	6.91	7.11	6.98	7.04	7.01	N/A	N/A	N/A	N/A
Heat Content (10^6 Btu/ton)	22.83	20.47	19.62	20.50	20.00	20.50	20.00	20.25	N/A	N/A	N/A	N/A
Wt % S	1.10	1.10	0.87	0.95	0.86	0.90	0.90	0.90	N/A	N/A	N/A	N/A
Oil Usage (10^3 gal)	622.0	1,216.7	1,198.0	794.0	20,313.8	5,277.0	5,277.0	10,553.9	N/A	N/A	N/A	N/A
Heat Content (10^6 Btu/10^3 gal)	138.556	137.989	138.551	138.000	138.000	138.000	138.000	138.000	N/A	N/A	N/A	N/A
Wt % S	0.30	0.15	0.28	0.41	0.42	0.42	0.41	0.41	N/A	N/A	N/A	N/A
Total Heat Input (10^6 Btu/yr)	17,919,501	20,152,750	18,400,946	17,343,116	21,530,544	10,004,881	9,431,949	19,436,830	N/A	N/A	N/A	N/A
NO_x [b]	896.0	1,007.6	920.0	867.2	1,076.5	500.2	471.6	971.8	404.7	-567.1	40.0	N
CO AOR	237.0	296.0	234.0	212.0	236.2	114.3	109.8	224.1	502.8	278.7	100.0	Y
SO_2 [c]	813.1	1,007.8	850.6	746.4	759.0	370.2	382.5	752.7	180.8	-571.9	40.0	N
H_2SO_4 [d] AP-42 (1998)	48.1	59.9	45.3	44.5	51.3	24.4	23.5	47.9	33.2	-14.7	7.0	N
PM_{10} [e]	89.6	100.8	92.0	86.7	107.7	50.0	47.2	97.2	355.7	258.5	15.0	Y
PM [e]	89.6	100.8	92.0	86.7	107.7	50.0	47.2	97.2	355.7	258.5	25.0	Y
Pb AOR	5.2	6.5	6.2	5.6	0.2	1.5	1.4	2.9	0.5	-2.4	0.6	N
VOC AP-42 (1998)	43.2	53.9	51.2	46.3	53.5	25.4	24.5	49.9	49.1	-0.9	40.0	N

(a) Fuel data represents 1999, 2000 average for Units 3 and 4.
(b) Actual emissions based on 0.10 lb/MMBtu emission rate per EPA/TEC Consent Decree.
(c) Actual emissions reduced by 95% per EPA/TEC Consent Decree.
(d) Actual emissions reduced by 35% to reflect retroactive BACT.
(e) Actual emissions based on 0.010 lb/MMBtu emission rate per EPA/TEC Consent Decree.

Sources: ECT, 2001.
TEC, 2001.

APPENDIX E
DISPERSION MODELING FILES

TECO

TAMPA ELECTRIC

RECEIVED

JUL 03 2003

BUREAU OF AIR REGULATION

July 2, 2003

Mr. Lynn Haynes
Region IV
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7922 8030 2699

Ms. Trina Vielhauer
Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7922 8030 0652

File in
PSD-FL-301A
no need to scan

Re: Tampa Electric Company
Bayside Power Station Unit 2
Anticipated Commercial Operations Notification
Air Permit No. PSD-FL-301A
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Haynes and Ms. Veilhauer:

Tampa Electric Company (TEC) is notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the anticipated date of initial commercial operations as required by 40 CFR 75.61(a)(2)(i), the designated representative for an affected unit shall submit written notification: For a new unit or a newly affected unit, of the planned date when a new unit or newly affected unit will commence commercial operation or, for new stack or flue gas desulfurization system, of the planned date when a new stack or flue gas desulfurization system will be completed and emissions will first exit to the atmosphere. Notification of the planned date shall be submitted not later than 45 days prior to the date the unit commences commercial operation, or not later than 45 days prior to the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere. TEC hereby gives notice of commercial operation, for environmental purposes, of Bayside Power Station Unit 2 will be on or about November 16, 2003. Bayside Power Station Unit 1 (BPS) consists of three General Electric PG7241FA, 169 megawatt Gas Turbines (GT) at the BPS facility. Each of these three GT's, Bayside 2A, 2B, 2C and 2D, has a 150 foot stack and is connected to its own Heat Recovery Steam Generator. Since it is still uncertain in which order the GTs will begin commercial operations, TEC is giving notification that the GTs may commence commercial operations in the following order and on or about the following dates:

BPS 2A- September 17, 2003
BPS 2B- September 10, 2003
BPS 2C- October 9, 2003
BPS 2D- November 16, 2003

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5358.

Sincerely,

Dru Latchman

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

EA/bmr/DNL177

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC
Mr. S. Sheplak- FDEP
Mr. M. Oliva- CAMD

TECO

TAMPA ELECTRIC

RECEIVED

SEP 04 2003

BUREAU OF AIR REGULATION

September 3, 2003

Mr. Lynn Haynes
Region IV
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7914 8920 0770

Ms. Trina Vielhauer
Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7903 9774 7808

For the main file. Thank you. T

Re: Tampa Electric Company
Bayside Power Station Unit 2
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Haynes and Ms. Vielhauer:

Tampa Electric Company (TEC) is in the process of starting up Bayside Power Station Unit 2. Enclosed is the Test Protocol that TEC will be using to perform the initial compliance testing and the initial Continuous Emissions Monitoring System certification.

If you have any questions, please call Greer Briggs or me at (813) 641-5034.

Sincerely,

Laura A. Crouch

Greer Briggs for
Environmental Engineer- Air Programs
Environmental Affairs

EA/bmr/GMB1

Enclosure

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP (enc)
Mr. M. Oliva – CAMD (enc)
Mr. S. Sheplak- FDEP
Mr. S. Woodard- EPCHC (enc)

TECO
TAMPA ELECTRIC

TEST PROTOCOL

Initial Compliance Testing and CEM Certification
For
Units 2A, 2B, 2C and 2D Natural Gas Fired Turbines

At

Bayside Power Station

Tampa, Florida

Prepared for
Tampa Electric Company
By
Environmental Services
Of
Tampa Electric Company

August 29, 2003

TABLE OF CONTENTS

1.0 Introduction

Compliance emissions performance tests and CEM certification tests will be performed on Bayside Units 2A, 2B, 2C and 2D combined cycle combustion turbines and respective CEMS systems. The CEM test audits required for certification will be conducted in accordance with the conditions and monitoring requirements in Air Operating Permit 0570040-AC, with EPA 40 CFR Part 75, Subpart C, section 2.0, and the site CEM monitoring plan. Testing requirements for emissions compliance certification will be conducted in accordance with EPA 40 CFR Part 60, Appendix A, "Specifications and Test Procedures" on each Turbine outlet connected to a Heat Recovery Steam Generator (HRSG).

Each CT contains Dry Low NOx burners along with a Selective Catalytic Reduction unit (SCR) for the reduction and control of NO_X emissions. Anhydrous Ammonia is injected into the SCR catalyst which reacts with NO_X to reduce the NOx levels. During this process, small amounts of ammonia may "slip" past the catalyst and out of the stack to the atmosphere. To measure the ammonia slip concentration, emissions compliance testing will be conducted in accordance with the test procedures described in the applicable permit and EPA Conditional Test Method 027 (CTM-027).

Testing and certification for NOx and CO will be conducted to meet the requirements of Performance Specification 2, "Specifications and Test Procedures for SO_2 and NO_X Continuous Emissions Monitoring Systems in Stationary Sources", and Performance Specification 4, "Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources".

Combustion Turbines CT-2A, CT-2B, CT-2C and CT-2D Continuous Emissions Monitoring Systems, consist of NO_X, CO, and CO_2 instruments located on the outlet.

1.1 Facility Description

Source:	The 4 Bayside Units 2A, 2B, 2C and 2D General Electric Frame 7FA turbines are individual natural gas fired combined cycle combustion turbines connected to an unfired HRSG with additional steam delivery to Gannon Station unit 6 generator. Each Bayside CT has a generating capacity of approximately 169 MW with an additional generation of approximately 414 MW. Exhaust from the CT is directed through an HRSG duct, which contains a SCR catalyst using ammonia injection for the control of NO_X into the atmosphere.
Location:	Bayside Station is located at Port Sutton Road, Tampa, Hillsborough County, Florida.
CEMS Manufacturer:	Spectrum Systems Inc. 3410 West 9 Mile Road Pensacola, Florida 32526 (850) 944-3392
Test Coordinator:	Environmental Affairs, Environmental Services Tampa Electric Company 5010 Causeway Blvd Tampa, Florida 33619 (813) 630-7382

1.2 Proposed Testing Schedule

The testing is tentatively scheduled to begin with Unit 2B on September 16, 2003 followed by Unit 2A on September 23, 2003. Units 2C and 2D are scheduled in November of 2003 pending construction progress and is subject to change based on unit operation, resource availability and/or equipment availability.

TABLE 1: TEST MATRIX

Tampa Electric Company, Bayside Station
Emissions Performance Testing and CEM Initial Certification of Four (4) GE 7FA Gas Turbines

Emissions Compliance Tests
Cycle Response Time Checks
Linearity Checks and Cylinder Gas Audits
Seven Day Drift Calibration Checks
Relative Accuracy Test Audits

Test Description	Turbine Unit No.	Load Range(mw)	Test Runs per Each Test Method						Test Run Time (hours)	Test Dates
			NH3 CTM-027	NOx RM-7E	SO2 D3246	CO2 RM-3A	CO RM-10	Moisture RM-4		
Cycle Response	Unit 2B	152 - 169		1		1	1		1	Sept. 2
Linearity Check	Unit 2B	152 - 169		3		3			2	Sept. 2
7-Day Drift	Unit 2B	152 - 169		7		7			8	Sept. 8
Gas RATA	Unit 2B	152 - 169		9		9	9	9	10	Sept. 16
Emissions Test	Unit 2B	152 - 169	3		1			3	8	Sept. 17
Cycle Response	Unit 2A	152 - 169		1		1	1		1	Sept. 9
Linearity Check	Unit 2A	152 - 169		3		3			2	Sept. 9
7-Day Drift	Unit 2A	152 - 169		7		7	7		8	Sept. 17
Gas RATA	Unit 2A	152 - 169		9		9	9	9	10	Sept. 24
Emissions Test	Unit 2A	152 - 169	3		1			3	8	Sept. 25
Cycle Response	Unit 2C	152 - 169		1		1	1		1	Nov. 1
Linearity Check	Unit 2C	152 - 169		3		3			2	Nov. 1
7-Day Drift	Unit 2C	152 - 169		7		7	7		8	Nov. 8
Gas RATA	Unit 2C	152 - 169		9		9	9	9	10	Nov. 18
Emissions Test	Unit 2C	152 - 169	3		1			3	8	Nov. 19
Cycle Response	Unit 2D	152 - 169		1		1	1		1	Nov. 9
Linearity Check	Unit 2D	152 - 169		3		3			2	Nov. 9
7-Day Drift	Unit 2D	152 - 169		7		7	7		8	Nov. 16
Gas RATA	Unit 2D	152 - 169		9		9	9	9	10	Nov. 25
Emissions Test	Unit 2D	152 - 169	3		1			3	8	Nov. 26

*Note: Test reports will be filed separately for each unit due to the time spans in between.

2.0 Testing Protocol

The Bayside Units 2, A through D, Continuous Emissions Monitoring System consists of an outlet CEMS to measure the flue gases exiting the stack and entering the atmosphere.

The outlet CEMS systems consist of a dual range NO_X monitor, a CO_2 monitor and a dual range CO monitor. Each gas monitor is a dry sample by volume straight extractive system with heat traced sample lines and a sample-conditioning condenser to remove moisture from the sample, prior to delivery to the analyzers.

2.1 Shelter Certification

All audit testing performed from the CEMS shelter will be conducted while the unit(s) are operating at conditions of typical temperatures and pressures.

2.1.1 Cycle Response Time Tests

A Cycle Response Time Test will be conducted on both ranges of each NO_X and CO_2 monitor (excluding the CO monitor) of each CEM rack, in accordance with the requirements of EPA 40 CFR Part 75, Appendix A, "Specification and Test Procedures", section 6, "Certification Tests and Procedures", § 6.4, "Cycle Time Test".

The upscale analyzer response is measured by introducing a calibration zero gas to the sample system and allowed to be drawn by the analyzer. Once stable, the system is allowed to sample the flue gas concentration and a recording of the time it takes the system to measure 95% of the step change value between the starting gas value and the ending gas value. The analyzer downscale response is measured by introducing zero calibration gas again and recording the response time it takes to fall from the flue gas concentration to 95% of the step change value between the starting gas value and the ending gas value.

2.1.2 Linearity Check

The NO_X and CO_2 analyzers and the supporting sampling system are challenged with a known value of calibration gases to conduct a linearity check on the CEMS system. These required linearity checks will be performed in accordance with the procedures detailed in EPA 40 CFR Part 75, Appendix A, "Specifications and Test Procedures", §6.2, and will be performed at the gas concentrations specified in §3.2. Specifically, these gas concentrations are defined as low-level, mid-level, and high-level as defined in EPA 40 CFR Part 75, Appendix A, "Specifications and Test Procedures", § 5.2.1 and tabulated below:

Linearity Check "Point"	Linearity Check Gas Concentration
Low-level Concentration	20 to 30 percent of span
Mid-level Concentration	50 to 60 percent of span
High-level Concentration	80 to 100 percent of span

Linearity check cylinder gases will be introduced in such a manner so that the gas flows through the sample line and all filters, scrubbers, conditioners, and other monitor components used during normal sampling.

Linearity check cylinder gases will meet the criteria specified in the USEPA's Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, Procedure G1.

Linearity check cylinder gases will be introduced to the CEMS in a manner controlled by the system programmable controller. A programmed calibration cycle module will be used to control the flow of the linearity check gases. The standard calibration cycle consists of three events in the following sequence: High-level, mid-level, and low-level gas concentrations for the analyzer(s) under test. During the calibration cycle, each gas is introduced to the CEMS for a total of 5 minutes. The plant Data Acquisition and Handling System (DAHS) will record the response, and these responses will be used to perform the linearity assessment.

Each linearity check will consist of a series of three initiations of the programmed calibration cycle for each analyzer to be tested. The linearity check will test the CEMS in the following sequence:

NO_X and CO_2 Analyzers (high range outlet)
Low-level gas
Mid-level gas
High-level gas

NO_X and CO_2 Analyzer
Low-level gas
Mid-level gas
High-level gas

NO_X and CO_2 Analyzer
Low-level gas
Mid-level gas
High-level gas

At the end of the linearity check test cycle, a printout of the system responses will be obtained from the plant DAHS. This printout will serve as the official record of the linearity check and will be the source of the data used to perform the linearity check accuracy assessment.

2.1.3 CO Cylinder Gas Audit

The CO analyzer and supporting sampling system are challenged with a known value of calibration gases to conduct a Cylinder Gas Audit (CGA) on the dual range CO CEMS system. The CO CGA will be conducted at both ranges in accordance with procedures detailed in EPA 40 CFR Part 60, Appendix F, § 5.1.2. The system is challenged with two gas concentrations; specified as mid and high points of the analyzer scale as tabulated below:

Audit Check "Point"	Audit Check Gas Concentration
Mid-level Concentration	20 to 30 percent of span
High-level Concentration	50 to 60 percent of span

CGA cylinder gases will be introduced in such a manner so that the gas flows through the sample line and all filters, scrubbers, conditioners, and other monitor components used during normal sampling. During the calibration cycle, each gas is introduced to the CEMS for a total of 5 minutes. The plant Data Acquisition and Handling System (DAHS) will record the response, and these responses will be used to perform the CGA assessment.

At the end of the CGA test cycle, a printout of the system responses will be obtained from the plant DAHS. This printout will serve as the official record of the CGA check and will be the source of the data used to perform the CGA accuracy assessment.

2.1.4 Seven Day Calibration Error Test

A 7-day Calibration Error Test will be conducted on each NO_X and CO_2 analyzer in accordance with the requirements of EPA 40 CFR Part 75, Appendix A, "Specification and Test Procedures", section 3, "Performance Specifications", § 3.1 and section 6, "Certification Tests and Procedures", § 6.3.1, "Gas Monitor 7-day Calibration Error Test". On each CO analyzer, a 7-day Calibration Error Test will also be conducted and in accordance with EPA 40 CFR Part 60, Performance Specification 4, "Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources".

On each gas monitor a known gas concentration at the zero level and high gas levels are introduced to the CEM system to measure the calibration error for seven consecutive operating days (not consecutive calendar days). The calibration gas shall pass through all filters, scrubbers, conditioners and other monitoring components used during normal sampling as practical. Each daily calibration measurement shall be approximately 24 hours apart and no adjustments made to the analyzer until the 7^{th} day check is complete.

2.2 Stack testing and Relative Accuracy Test Audits (RATA)
The NO_X and CO_2 RATA testing will be conducted in accordance with EPA 40 CFR Part 60, Appendix A, "Test Methods and Procedures", and with EPA 40 CFR Part 75, Appendix A, "Specification and Test Procedures", section 3, "Performance Specifications", § 3.3 and section 6, "Certification Tests and procedures, § 6.5, "Relative Accuracy and Bias Tests (General Procedures). The CO RATA testing will be conducted in accordance with EPA 40 CFR Part 60, Appendix A, "Test Methods and Procedures", and Appendix B, Performance Specification 4, "Specifications and Test Procedures for Carbon Monoxide Continuous Emissions Monitors in Stationary Sources".

RATA testing and sampling will be conducted using USEPA RM 3A, 7E, 20 and 10 for CO_2, NO_X and CO respectively. Each RATA will consist of a minimum of 9, and a maximum of 12, twenty-one minute test runs. A calibration will be performed both prior to and immediately following each test run, with the results of these calibrations used to "correct" the average concentration recorded during the run. A printout of the response recorded by the plant's DAHS for time frame corresponding to the test run will be obtained and compared to the value obtained from the test run.

Relative Accuracy (RA) will be assessed after nine qualified runs have been completed and calculated using the equations in accordance with EPA 40 CFR Part 75, Appendix A, section 7.

RA is considered acceptable based on the following criteria:

The RA for CO_2 shall be $\leq$7.5% for annual criteria but not to exceed 10%. There are no emission rate limits or bias adjustment factors for CO_2.

The RA for NO_X shall be $\leq$7.5% for annual criteria but not to exceed 10%, for units where the average of the monitoring system measurements of NO_X emission rate during the RATA is less than or equal to 0.200 lb/mmBtu, the mean value of the NO_X continuous emission monitoring system measurements is within $\pm$ 0.015 lb/mmBtu of the reference method mean value whenever the RA specification of 7.5% is not achieved.

The RA for the CO CEMS shall be between no greater than 10 percent of the mean value of the RM test data in terms of the units of the emission standard (CO ppmvd @ 15% O_2) or 5 percent of the applicable standard (7.8 ppmvd @ 15% O_2), whichever is greater.

The NO_X and CO_2 monitoring system will be tested for Bias after each RATA. The Bias test will pass if the mean difference of the data set comprised of the individual differences is less than the confidence coefficient of the data set. Should this Bias test fail, a Bias Adjustment Factor (BAF) will be calculated using the equations in EPA 40 CFR Part 75, Appendix A, section 7.

This BAF is then applied prospectively to all monitoring system data from the date and time of the failed Bias test, until the date and time of a new RATA producing a new BAF.

2.3 Emissions Compliance Testing

Emissions Compliance Testing for CO, NO_X and Ammonia Slip (NH_3) will be conducted on the outlet stack of each turbine. Sulfur content of the fuel will be tested by fuel analysis from the gas stream. The compliance testing for CO and NO_X will be performed in conjunction with the CEM RATA tests using USEPA Reference Methods 10 and 20 respectively. Nine qualified RATA runs shall represent three 63-minute test runs for CO and NO_X. NH_3 will be conducted manually with Conditional Test Method 027 using three, 1-hour test runs and thirty cubic feet of sample volume. Compliance testing will be conducted in accordance with EPA 40 CFR Part 60; Appendix A, "Test Methods and Procedures", Subpart GG, and the applicable permit requirements.

3.0 Test System Descriptions

3.1 Exhaust Gas Measurements

A transportable laboratory grade analyzer system (TCEMS) will be used with continuous monitors capable of measuring NO_X, CO and CO_2. Each analyzer will be calibrated in the field and QA/QC procedures will be performed as required by each EPA test method. Following initial calibrations of the equipment, a sample of exhaust gas will be continuously extracted from the exhaust stack and delivered to each individual analyzer at the same flow rate as used for instrument calibration. The results of these measurements will be recorded on a portable personal computer to document the sample analysis, calibrations and quality assurance activities conducted during the tests. All results are stored on the computer hard drive.

3.2 EPA Method 3A for O_2/CO_2

CO_2 will be measured using a Servomex 1400B Oxygen/Carbon Monoxide analyzer, which measures the O_2 by paramagnetic detector and the CO_2 by infrared absorption. The CO_2 is measured in a dry sample by volume.

3.3 EPA Method 7E/20 for NO_X

NO_x concentrations will be measured according to USEPA RM 7E applications using a Thermo Environmental 42C NO/NO_x analyzer that uses the measurement technique of chemiluminescence. The NO_X concentration is also measured on a dry basis and the sample reported corrected to 15% O_2 concentration and in pounds per million British thermal units emission rate (lbs/mmBtu). In accordance with USEPA RM 20, daily converter efficiency tests will be performed on the instruments NO to NO_2 converter chamber by mixing a known concentration of NO cylinder gas and clean air in a tedlar bag and drawn by the instrument at normal sampling rates for 30 minutes.

Prior to RATA and emissions compliance sampling activities and concurrently with NO_X measurements, O_2 measurements will take place in accordance with the site Air Operating Permit, and EPA 40 CFR Part 60, Subpart GG, "Standards of Performance for Stationary Gas Turbines". An initial stratification test will be conducted in the stack for each turbine at full load capacity and steady state conditions.

3.4 EPA Method 9 for Visible Emissions

Visible Emissions Observations (VEO) will be conducted by a state certified reader on each individual turbine for 60 minutes at 15-second intervals. The highest six-minute average and total 60-minute average computed for final results, reported in percent opacity.

3.5 EPA Method 10 for CO

CO concentrations will be measured using a Thermo Environmental Model 48C CO analyzer that uses the measurement technique of infrared light source. The CO concentration is also measured on a dry basis and CO will be reported in ppm.

3.6 EPA Method CTM-027 for NH_3 Slip

NH_3 slip concentrations will be measured using an isokinetic manual sample train to draw sample gas from the outlet. The NH3 slip concentration is measured on a dry basis and corrected for moisture in the sample. NH_3 slip concentrations will be reported corrected at 15% O_2.

An alternative method for NH_3 slip may also be used in conjunction with CTM-027 by instrumental sampling with a NTIR (Infrared) detection analyzer from California Analytical Instruments. This instrument uses a five-second slip sample for an integrated measurement with Photo-Acoustics and Infrared technology.

3.7 CEM Operational Data

CEM operational data will be provided by Bayside Station to document the unit's operating parameters during the test. The test data will be collected from the CEM System Software for each test run in one-minute averages.

3.7.1 CO_2 in percent volume
3.7.2 NO_X in ppm
3.7.3 NO_X in lbs/mmBtu
3.7.4 CO in ppm
3.7.5 Generation in megawatts
3.7.6 Turbine Exhaust Temperature in degrees F
3.7.7 NH_3 injection rate in gpm
3.7.8 Fuel flow in Kscfps
3.7.9 Compressor discharge temperature, degrees F
3.7.10 Compressor inlet temperature, degrees F
3.7.11 Specific Humidity
3.7.12 SCR inlet and outlet temperatures, degrees F

3.8 Methods for Fuel Analysis

Natural gas fuel composition analysis will be conducted from samples retrieved at the line feeding the turbine in accordance with GPA method 2261. Fuel composition will be used to determine the heating value of the fuel and to develop "F factors" used in determining mass emission rates. Sulfur content of the fuel will be performed by ASTM method D3246. Moisture content of the fuel will be performed by ASTM method D4888.

4.0 Quality Assurance/Quality Control Activities

4.1 Zero and span calibration bias/drift checks will be conducted before and after each test run. Test run validated by $\pm$ 3% drift from full-scale response and by $\pm$ 5% bias from each previous calibration. Emission concentration measurements corrected for zero and span drift and calibration bias.

4.2 NO_X analyzer NO_2 to NO converter efficiency check results to verify a minimum 90% converter efficiency.

4.3 Calibration gases traceable to EPA Protocol 1 (G1 analysis) and the National Institute of Standards and Technology (NIST).

4.4 Multi-point instrument calibration error test ± 2% linearity check.
4.5 All sampling and analysis conducted on site with on-site results.

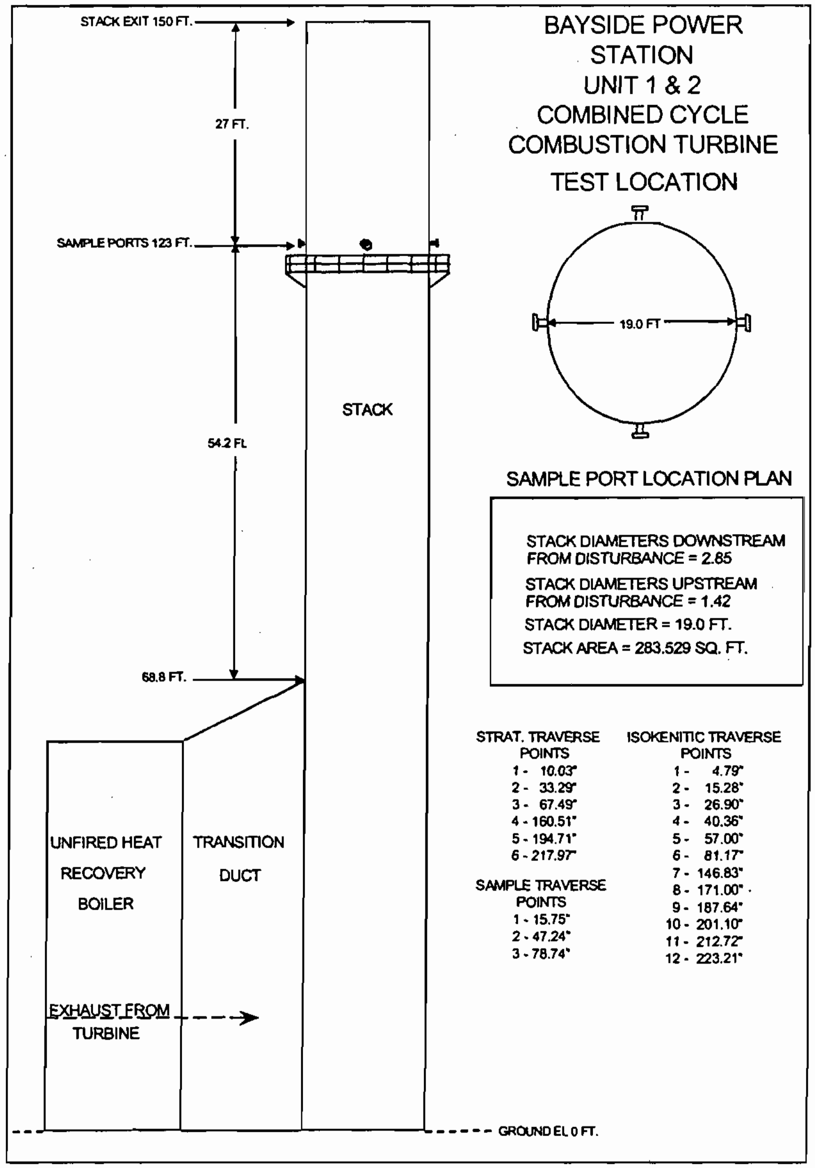
Table 2: Anticipated Analyzer Spans and Calibration Gas Values

CALIBRATION GAS VALUES				
ANALYZER	SPAN	LOW-SCALE	MID-SCALE	HIGH-SCALE
NO_X	0-10 ppm	3 – 4 ppm	5 – 6 ppm	8 – 10 ppm
CO	0-20 ppm	6 – 8 ppm	10 – 12 ppm	16 – 20 ppm
CO_2	0-20%	6.0 - 8.0%	10.0 - 12.0%	16.0 - 20.0%

The ranges displayed in Table 2 are predicted values for the reference method analyzers.

APPENDICES:
Appendix A – Source Location Diagrams
Appendix B – Example Run Calibration Forms
Appendix C – Example Calibration Certificates
Appendix D – Example Quality Control Activities

Appendix A
Source Location Diagrams



SAMPLING LOCATION

Appendix B
Example Run Calculation Forms

Big Bend CS01W RATA - Report						
RUN 1						
07/16/2003						
9:32						
Linearity Check - Calibration Error	O2	CO2	CO	NO	NOX	SO2
Analyzer Range	0.000	20.000	0.000	0.000	600.000	280
Units	PPM	%	PPM	PPM	PPM	PPM
Low Level Certified Value (PPM or %)						
Mid Level Certified Value (PPM or %)		11.02			357	108.2
High Level Certified Value (PPM or %)		18.18			561	276
Zero Level Observed	-	0.081	-	-	0.014	-0.266
Low Level Observed	-	-	-	-	-	-
Mid Level Observed	-	11.097	-	-	359.039	107.4
High Level Observed	-	18.173	-	-	562.007	275.3
% Difference from Zero to Target	Inactive	0.40	Inactive	Inactive	0.00	-0.10
% Difference from Low to Target	Inactive	0.00	Inactive	Inactive	0.00	0.00
% Difference from Mid to Target	Inactive	0.38	Inactive	Inactive	0.34	-0.30
% Difference from High to Target	Inactive	-0.04	Inactive	Inactive	0.17	-0.25
Analyzer Range	0.000	20.000	0.000	0.000	600.000	280
Units	PPM	%	PPM	PPM	PPM	PPM
Actual Zero From Linearity	0.0	0.08100	0	0	0.01400	-0.27
Actual Span From Linearity	0	11.0970	0	0	562.007	107.4
Initial Readings						
Zero	-	0.116	-	-	0.629	-0.238
Span	-	10.951	-	-	557.846	106.8
Final Readings						
Zero	-	0.169	-	-	0.717	0.131
Span	-	11.019	-	-	557.172	107.2
Initial Sampling System Bias						
Zero Bias (Run-System Cal)	Inactive	0.18	Inactive	Inactive	0.10	0.01
Span Bias	Inactive	-0.73	Inactive	Inactive	-0.69	-0.18
Final Sampling System Bias						
Zero Bias (Run-System Cal)	Inactive	0.44	Inactive	Inactive	0.12	0.14
Span Bias	Inactive	-0.39	Inactive	Inactive	-0.81	-0.06
Calculated Drift						
Zero Drift (Run-Run)	Inactive	0.27	Inactive	Inactive	0.01	0.13
Span Drift	Inactive	0.34	Inactive	Inactive	-0.11	0.12
Run Results						
Raw Results	NaN	12.17	NaN	NaN	407.97	102.2
Corrected Results (ppmv)	Inactive	12.22	Inactive	Inactive	410.34	103.3

Appendix C
Example Calibration Certificates

RATA CLASS CES HLP 1

Dual-Analyzed Calibration Standard

Scott Specialty Gases

1750 EAST CLUB BLVD,DURHAM,NC 27704 Phone: 919-220-0803 Fax: 919-220-0808

CERTIFICATE OF ACCURACY: Interference Free™ Multi-Component EPA Protocol Gas

Assay Laboratory
SCOTT SPECIALTY GASES
1750 EAST CLUB BLVD
DURHAM,NC 27704

P.O. No.: E-N75518
Project No.: 12-37270-001

Customer
Tampa Electric Co
STEVE KELLY
5010 CAUSEWAY BLVD
TAMPA, FL 33619 FL 33619

ANALYTICAL INFORMATION

This certification was performed according to EPA Traceability Protocol For Assay & Certification of Gaseous Calibration Standards; Procedure #G1; September, 1997.

Cylinder Number: ALM001853 Certification Date: 2/02/00 Exp. Date: 2/01/2002
Cylinder Pressure***: 1944 PSIG

COMPONENT	CERTIFIED CONCENTRATION (Moles)		ACCURACY**	TRACEABILITY
CARBON DIOXIDE	5.13	%	+/- 1%	Direct NIST and NMi
NITRIC OXIDE	201.5	PPM	+/- 1%	Direct NIST and NMi
SULFUR DIOXIDE *	150.0	PPM	+/- 1%	Direct NIST and NMi
NITROGEN - OXYGEN FREE		BALANCE		
TOTAL OXIDES OF NITROGEN	204.	PPM		Reference Value Only

*** Do not use when cylinder pressure is below 150 psig.
** Analytical accuracy is based on the requirements of EPA Protocol procedure G1, September 1997.
Product certified as +/- 1% analytical accuracy is directly traceable to NIST or NMi standards.
* This Protocol has been certified using corrected NIST SO2 standard values, per EPA guidance dated 7/24/96 and will not correlate with uncorrected Protocols.

REFERENCE STANDARD

TYPE/SRM NO.	EXPIRATION DATE	CYLINDER NUMBER	CONCENTRATION	COMPONENT
NTRM 5000	7/13/01	ALM049023	5.032 %	CARBON DIOXIDE
NTRM1686	2/01/03	ALM030775	495.3 PPM	NO/N2
NTRM1661	10/02/02	ALM090564	488.5 PPM	SO2/N2

INSTRUMENTATION

INSTRUMENT/MODEL/SERIAL#	DATE LAST CALIBRATED	ANALYTICAL PRINCIPLE
VARIAN GC/3400/0160-C02	01/24/00	GC / TCD
FTIR System/8220/AAB9400252	01/21/00	Scott Enhanced FTIR
FTIR System/8220/AAB9400252	01/21/00	Scott Enhanced FTIR

ANALYZER READINGS

(Z = Zero Gas R = Reference Gas T = Test Gas r = Correlation Coefficient)

First Triad Analysis			Second Triad Analysis			Calibration Curve	
CARBON DIOXIDE							
Date:01/24/00	Response Unit:ACR					Concentration = A + Bx + Cx2 + Dx3 + Ex4	
Z1 = 0.0000	R1 = 34026.	T1 = 34869.				r = 0.999990	
R2 = 34062.	Z2 = 0.0000	T2 = 34749.				Constants:	A = 0.000000
Z3 = 0.0000	T3 = 34892.	R3 = 34091.				B = 1.000000	C = 0.000000
Avg. Concentration:	5.130	%				D = 0.000000	E = 0.000000
NITRIC OXIDE							
Date:01/21/00	Response Unit:PPM		Date:02/02/00	Response Unit: PPM		Concentration = A + Bx + Cx2 + Dx3 + Ex4	
Z1 = 0.1733	R1 = 495.61	T1 = 200.68	Z1 = 0.0084	R1 = 495.25	T1 = 202.36	r = 0.999990	
R2 = 494.58	Z2 = 0.2433	T2 = 200.37	R2 = 496.10	Z2 = 0.0883	T2 = 202.20	Constants:	A = 0.000000
Z3 = 0.0985	T3 = 200.91	R3 = 495.70	Z3 = -0.009	T3 = 202.40	R3 = 494.58	B = 1.000000	C = 0.000000
Avg. Concentration:	200.8	PPM	Avg. Concentration:	202.3	PPM	D = 0.000000	E = 0.000000
SULFUR DIOXIDE *							
Date:01/21/00	Response Unit:PPM		Date:02/02/00	Response Unit: PPM		Concentration = A + Bx + Cx2 + Dx3 + Ex4	
Z1 = 0.0195	R1 = 488.57	T1 = 151.13	Z1 = 0.2618	R1 = 489.01	T1 = 149.43	r = 0.999990	
R2 = 489.28	Z2 = 0.1908	T2 = 150.96	R2 = 488.27	Z2 = 0.0394	T2 = 149.02	Constants:	A = 0.000000
Z3 = 0.2890	T3 = 150.94	R3 = 488.65	Z3 = 0.2955	T3 = 148.56	R3 = 488.22	B = 1.000000	C = 0.000000
Avg. Concentration:	151.0	PPM	Avg. Concentration:	149.0	PPM	D = 0.000000	E = 0.000000

APPROVED BY: BMB
B. M. Becton

TECO
TAMPA ELECTRIC

PITOT TUBE CALIBRATION DATA SHEET

Pitot Tube ID# pf05
Calibration Date: 07/08/2003
Openings Damaged? ☐ Y ☑ N

Operating Quarter: 3
Repaired? ☐ Y ☑ N ☐ N/A

Alpha and Beta Angle Determinations

$\alpha 1$	1.9	degrees	*Pass*
$\alpha 2$	1.8	degrees	*Pass*
$\beta 1$	2.6	degrees	*Pass*
$\beta 2$	1.3	degrees	*Pass*

Gamma, Theta, A, Z, and W Determinations

ψ	1	degrees	
A	2.4	cm	
Z	0.042	cm	*Pass*
o	1.8	degrees	
W	0.075	cm	*Pass*

Acceptable Limits:

Dt 0.48 < Dt > 0.95 cm
α < 10 degrees
($\alpha 1$ measured across top impact openings)
($\alpha 2$ measured across bottom impact openings)
$\beta 1$ < 5 degrees (alongside top impact openings)
$\beta 2$ < 5 degrees (alongside bottom impact openings)
Z < 0.32 cm (Asinψ)
W < 0.08 cm (Asino)
A distance between tips
o angle of plane on side of pitots
ψ angle between tips

NOTES

All measurements are taken in accordance with the requirements of 40 CFR 60 Appendix A - Test Methods, Method 2, "Determination of stack gas velocity and volumetric flow rate (Type S pitot tube)". Measurement details are found in EPA/600/4-77/027b, "Quality Assurance Handbook for Air Pollution Measurement Systems: Stationary Source Specific Methods", sub-section 3.1.1, Procurement of Apparatus and Supplies.

Comments: FIXED
Cp = 0.803

Calibrated by:
Printed Name: JORGE A VARINO
Date: 07/08/2003

Quality Assurance Review / Approval:
Date:

Appendix D
Example Quality Control Activities

TECO
TAMPA ELECTRIC

Reference Method 20
Converter Efficiency Test
Data Summary

Analyzer Serial Number: 42CHL-75521-330
Test Date: 06/24/2003

Maximum 1-minute Value in 30-minute Period:	15.43	ppm
Value at End of 30-minute Period:	15.42	ppm
Difference Observed:	-0.01	ppm
Converter Efficiency:	99.94	%
Percent Decrease:	0.06	%

Converter Efficiency calculated as:

$$\frac{\text{Value at End of 30-minute Period}}{\text{Maximum Value in 30-minute Period}} \times 100$$

Converter is acceptable providing decrease is less than or equal to 2.0%

SO2, NOx, CO2 RATA Run Information Sheet-

Run 1			
Start time (hhmm):		1244	
Stop time (hhmm):		1305	
Calibration Responses			
	Initial	Final	
Zero	0	0	ppm SO2
Up-scale	1	1	ppm SO2
Zero	0.028	0.139	ppm NOx
Up-scale	12.611	12.691	ppm NOx
Zero	-0.007	0.013	% CO2
Up-scale	10.907	10.902	% CO2
Average RM Values for Run			
	1 ppm SO2		
	9.34 ppm NOx		
	4.15 % CO2		
Average CEM Values for Run			
	1 ppm SO2		Bias Test
	8.749 ppm NOx		Pass
	0.029 lbs NOx		Drift Test
	3.755 % CO2		Pass
	152.227 Unit(s) Load		

TAMPA ELECTRIC

RECEIVED

AUG 28 2003

BUREAU OF AIR REGULATION

August 27, 2003

Mr. Lynn Haynes
Region IV
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7929 5739 0434

Ms. Trina Vielhauer
Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7908 8337 8939

For the main files. Thx! T

Re: **Tampa Electric Company**
Bayside Power Station Unit 2
Initial Compliance Testing
Air Permit No. PSD-FL-301A
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Hayes and Ms. Vielhauer:

Tampa Electric Company (TEC) is notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the initial compliance testing. As required by 40 CFR Part 60.8(a) and Condition 20 of permit PSD-Fl-301A, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s). Also as required by 40 CFR Part 60.8(d) and Condition 20 of permit PSD-FL-301A, the owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test. TEC hereby gives notice that the initial compliance test may be performed for Bayside Power Station (BPS) Unit 2 on the following dates:

BPS 2A- October 01, 2003
BPS 2B- October 02, 2003
BPS 2C- November 21, 2003
BPS 2D- November 22, 2003

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034.

Sincerely,

Laura R. Carson
for

Greer Briggs
Environmental Engineer- Air Programs
Environmental Affairs

EA/bmr/GMB102

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC
Mr. J. Kahn - FDEP
Mr. Manuel Oliva – CAMD
Mr. S. Sheplak – FDEP

TAMPA ELECTRIC

RECEIVED
AUG 28 2003
BUREAU OF AIR REGULATION

August 27, 2003

Mr. Lynn Haynes
Region IV
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7929 5739 0434

Ms. Trina Vielhauer
Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7908 8337 8939

Re: Tampa Electric Company
Bayside Power Station Unit 2
Initial Certification Testing
Air Permit No. PSD-FL-301A
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Hayes and Ms. Vielhauer:

Tampa Electric Company (TEC) is notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the initial Continuous Emissions Monitoring System (CEMS) certification test as required by 40 CFR Part 75.61(a)(1)(i), which states initial certification test notifications shall be submitted not later than 21 days prior to the first scheduled day of initial certification testing. TEC hereby gives notice that the initial CEM certification test may be performed for Bayside Power Station (BPS) Unit 2 on the following dates:

BPS 2A - September 9, 2003
BPS 2B - September 2, 2003
BPS 2C – October 31, 2003
BPS 2D - November 7, 2003

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034.

Sincerely,

Laura R. Coren
for
Greer Briggs
Environmental Engineer- Air Programs
Environmental Affairs

EA/bmr/GMB101

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC
Mr. J. Kahn - FDEP
Mr. Manuel Oliva - CAMD
Mr. S. Sheplak – FDEP

AK 3.11

TAMPA ELECTRIC

January 30, 2004

Ms. Deborah Getzoff
Southwest District
Florida Department of Environmental Protection
3804 Coconut Palm Drive
Tampa, Florida 33619

Via FedEx
Airbill No. 7905 3402 9178

Mr. Jerry Campbell
The Environmental Protection Commission
of Hillsborough County
1410 North 21st Street
Tampa, Florida 33605

Via FedEx
Airbill No. 7925 6039 9194

Re: **Tampa Electric Company**
Quarter III & IV, 2003
Bayside Semi-Annual Excess Emissions & Subpart GG Report
Air Construction Permit #0570040-015-AC
Air Permit Number: PSD-FL-301A
AIRS #0570040, E.U. ID#020, 021, 022

Dear Ms. Getzoff and Mr. Campbell:

As required by Section III, Specific Condition 25.and Section IV Appendix XS of the above referenced permit, TEC shall submit a semi-annual report to the Department of Environmental Protection and the Environmental Protection Commission of Hillsborough County, by January 30th of each year for Quarters 3 and 4, for each gas turbine summarizing the CEMS data and equipment. The report shall include: the monthly sulfur content (Attachment 1), the NO_x Excess Emissions Report, the 24-hour block average for each day of operation; the number of 1-hour emission averages excluded from each 24-hour average; the emissions due to monitor downtime; the reason for any monitor downtime; unusual maintenance or repair of the CEMS; a summary of any RATA tests performed, an updated general range of ammonia flow rates required to meet NO_x emissions limitations over the range of gas turbine load conditions (Attachments 2-4) and the Data Assessment Report (DAR) (Attachment 5) as required by Specific Condition 23.e.

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

If there are any questions regarding this report, please contact Laurie Pence or me at (813) 641-5060.

Sincerely,

Laurie A. Pence
for

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

EA/br/RPT001BPS Exc. Emis./GG Report Qtr 3/4, 03

Enclosures

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) 1/28/04

Signature Date

Wade A. Maye General Manager, Bayside Power Station

Name Title

ATTACHMENT 1

BAYSIDE POWER STATION
MONTHLY SULFUR CONTENT REPORT

Date	Sulfur Content (grains per 100 SCF)
July-03	0.0954
August-03	0.0922
September-03	0.0508

BAYSIDE POWER STATION
MONTHLY SULFUR CONTENT REPORT

Date	Sulfur Content (grains per 100 SCF)
October-03	0.0416
November-03	0.0592
December-03	0.0531

Note: 10/30/03-11/12/03 vendor analyzer out

ATTACHMENT 2

SUMMARY REPORT – NO_x EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE NSPS SUBPART GG

Pollutant: NOx - Combustion Turbine

Emission Limitation: 3.5 ppmvd @ 15% O_2 on a 24-hour block average

Reporting period dates: From 07/01/03 to 12/31/03

Company: Tampa Electric Company
Address: P.O. Box 111
Tampa, FL 33601-0111

Monitor Manufacturer and Model No.: Thermal Environmental 42CLS

Date of Latest CMS Certification or Audit: October 2003

Process Unit Description: 169 MW Combined Cycle Combustion Turbine (CT 1A)

Total source operating time in reporting period[1]: 3331.5

Emission Data Summary[1]		CMS Performance Summary[2]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown	223	a. Monitor equipment malfunctions	0
b. Control equipment problems	0	b. Non-Monitor equipment malfunctions	0
c. Process problems	4	c. Quality assurance calibration	36
d. Other known causes	20	d. Other known causes	10
e. Unknown causes	0	e. Unknown causes	0
2. Total duration of excess emission	247	2. Total CMS Downtime	46
3. Total duration of excess emissions x (100) / Total source operating time	7.0 %	3. Total CMS Downtime x (100) / Total source operating time	1.0 %

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.

This form is used for reporting excess emission according to New Source Performance Standard (NSPS) Subpart GG only. (CO is not a regulated by Subpart GG and is reported under the semi-annual excess emission report required by Section III, permit condition 25.)

1. For gases record all times in hours.

2. 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 60.7(c) shall be submitted.

   TEC Note: The summary report form and the excess emission report required will also be submitted in the semi-annual report.

Per Title V Permit #0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1A
24 - HOUR BLOCK AVERAGE - QUARTER 3, 2003

Date	24-hour block CO	24-hour block NOx
07/01/2003	0.7	3.0
07/02/2003	0.3	3.0
07/03/2003	0.3	3.0
07/04/2003	0.4	3.0
07/05/2003	0.3	3.0
07/06/2003	0.3	3.0
07/07/2003	0.4	3.0
07/08/2003	0.6	3.1
07/09/2003	0.6	3.5
07/10/2003	0.8	3.1
07/11/2003	0.5	2.9
07/12/2003	0.7	3.0
07/13/2003	0.6	3.0
07/14/2003	0.7	3.0
07/15/2003	0.7	3.0
07/16/2003	0.7	3.0
07/17/2003	0.8	3.0
07/18/2003	0.7	3.0
07/19/2003	0.8	3.0
07/20/2003	0.8	3.0
07/21/2003	0.9	3.0
07/22/2003	0.8	3.0
07/23/2003	0.8	3.0
07/24/2003	0.9	3.0
07/25/2003	1.0	3.0
07/26/2003	1.0	3.0
07/27/2003	1.1	3.0
07/28/2003	4.3	3.2
07/29/2003	1.2	3.3
07/30/2003	3.0	1.1
07/31/2003	1.3	3.2
08/01/2003	0.7	3.1
08/02/2003	0.7	3.0
08/03/2003	0.8	3.0
08/04/2003	0.8	3.1
08/05/2003	0.8	3.0
08/06/2003	0.9	3.1
08/07/2003	0.8	2.9
08/08/2003	0.7	2.9
08/09/2003	0.8	3.0
08/10/2003	0.8	3.0
08/11/2003	0.9	3.1
08/12/2003	1.0	3.0
08/13/2003	1.1	2.7
08/14/2003	0.9	3.1
08/15/2003	1.1	3.0
08/16/2003	1.2	2.9
08/17/2003	1.3	2.9
08/18/2003	0.7	2.5

-20

38

08/19/2003	0.4	2.9
08/20/2003	0.4	2.9
08/21/2003	0.4	2.9
08/22/2003	0.4	2.9
08/23/2003	0.5	2.9
08/24/2003	0.6	3.0
08/25/2003	0.6	2.9
08/26/2003	0.8	3.0
08/27/2003	0.7	2.9
08/28/2003	0.7	2.9
08/29/2003	0.8	2.7
08/30/2003	0.7	2.9
08/31/2003	0.8	2.9
09/01/2003	1.4	3.4
09/02/2003	0.8	2.9
09/03/2003	0.9	3.0
09/04/2003	1.0	2.9
09/05/2003	0.9	2.9
09/06/2003	0.9	2.9
09/07/2003	1.1	2.9
09/08/2003	1.2	2.8
09/09/2003	1.1	2.9
09/10/2003	0.9	2.9
09/11/2003	1.0	2.9
09/12/2003	1.0	2.9
09/13/2003	1.1	2.4
09/14/2003	1.1	2.9
09/15/2003	1.1	2.9
09/16/2003	0.6	2.9
09/17/2003	0.4	2.9
09/18/2003	0.5	2.9
09/19/2003	0.6	2.9
09/20/2003	0.5	2.9
09/21/2003	0.5	2.9
09/22/2003	0.6	2.9
09/23/2003	0.7	3.0
09/24/2003	0.7	2.9
09/25/2003	0.7	2.9
09/26/2003	0.7	2.9
09/27/2003	0.7	2.9
09/28/2003	0.7	2.9
09/29/2003	0.7	2.9
09/30/2003	0.8	2.9

—40

80

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

31
31
30
92 operating days

NOx
3.1 to 3.5
3.0 or less

CO
1.0 ppm or less 16

BAYSIDE POWER STATION - CT 1A
EXCLUDED DATA - QUARTER 3, 2003

Date	Hours Data Excluded	NOx Value of Excluded Data	CO Value of Excluded Data	Reason for Exclusion	
07/01/2003	2200	5.9	20.6	Shutdown	
07/02/2003	0900	47.8	197.6	Start-up	
07/08/2003	2300	10.2	86.4	Shutdown	
07/09/2003	0900	27.6	155.8	Start-up	
07/11/2003	0100	28.0	1241.0	Invalid Hour	I
	0900	39.7	975.3	Start-up	
	1000	52.1	877.1	Start-up	
	1100	22.2	157.9	Malfunction	M
	1700	9.6	278.6	Shutdown	
07/12/2003	0100	39.7	205.0	Shutdown	
07/14/2003	0300	44.9	649.4	Shutdown	
	0600	46.1	368.4	Start-up	
	0700	18.0	41.9	Start-up	
07/15/2003	2300	40.3	604.0	Shutdown	
07/16/2003	0700	28.3	118.0	Start-up	
07/17/2003	1900	24.0	327.6	Shutdown	
07/18/2003	1200	46.6	300.9	Start-up	
	1300	14.7	3.9	Start-up	
	1900	31.9	179.5	Shutdown	
07/19/2003	1000	21.1	359.1	Start-up	
	1100	35.9	266.6	Start-up	
	2200	6.2	38.2	Shutdown	
	2300	2.7	2756.9	Shutdown	
07/20/2003	1300	38.6	430.8	Start-up	
	1400	15.4	12.7	Start-up	
07/22/2003	2200	6.2	35.3	Shutdown	
	2300	4.4	2480.5	Shutdown	
07/23/2003	0800	7.1	525.5	Start-up	
	0900	24.3	150.2	Start-up	
07/24/2003	2300	8.2	175.4	Shutdown	
07/25/2003	0700	38.4	362.9	Start-up	
	0800	20.0	55.1	Start-up	
07/26/2003	2100	11.0	232.1	Shutdown	
07/27/2003	0900	35.0	380.1	Start-up	
	1000	10.2	24.8	Start-up	
07/29/2003	0800	25.1	111.8	Start-up	
07/30/2003	2400	41.9	741.2	Shutdown	
07/31/2003	0800	25.6	185.7	Start-up	
	2300	11.9	226.7	Shutdown	
08/01/2003	0900	24.4	429.1	Start-up	
	1000	22.3	95.4	Start-up	
08/04/2003	2400	11.2	358.1	Shutdown	
08/05/2003	0800	24.1	148.8	Start-up	
	2400	6.7	72.1	Shutdown	
08/06/2003	0700	15.2	94.7	Start-up	
	2300	8.5	106.7	Shutdown	
08/07/2003	0800	35.1	242.2	Start-up	
08/10/2003	2400	15.8	605.5	Shutdown	
08/11/2003	0600	34.5	132.3	Start-up	
	2300	20.2	322.2	Shutdown	
08/12/2003	0700	48.5	336.4	Start-up	
	2400	25	353	Shutdown	
08/13/2003	0700	67.6	189.6	Start-up	
	0800	5.2	*	Start-up	
	2300	11.3	452.8	Shutdown	
08/14/2003	0800	20.3	153.9	Start-up	
	2300	6.7	51.7	Shutdown	
	2400	8.4	2531.7	Shutdown	
08/15/2003	0700	22.7	161.2	Start-up	
08/19/2003	2200	12	162.6	Shutdown	
08/20/2003	0800	38.8	438.5	Start-up	

	0900	9.3	5.8	Start-up	
	2400	6.8	215.1	Shutdown	
08/21/2003	1300	25.3	175.5	Start-up	
08/22/2003	1900	5.5	20.7	Shutdown	
	2000	20.7	1431.6	Shutdown	
08/23/2003	1000	*	88	Start-up	
	1100	28.8	138.2	Start-up	
	2300	15.6	400.2	Shutdown	
08/24/2003	1000	33.7	259.7	Start-up	
08/27/2003	0100	27.3	1157.9	Shutdown	
	0900	20.1	157.9	Start-up	
08/28/2003	2200	35.5	721.1	Shutdown	
08/29/2003	0700	40.6	334.3	Start-up	
	0800	6.1	*	Start-up	
	2300	10.6	405.3	Shutdown	
08/30/2003	0900	33.2	215.2	Start-up	
08/31/2003	2300	18.9	447.5	Shutdown	
09/01/2003	0800	17.8	528.6	Start-up	
	0900	22.2	108.1	Start-up	
09/02/2003	0200	5.5	12.9	Shutdown	
	0300	36.9	1403.3	Shutdown	
	0700	29.1	80.4	Start-up	
	2300	9.4	109.2	Shutdown	
09/03/2003	0600	22.2	500.8	Start-up	
	0700	13.2	42.9	Start-up	
	2300	16.9	755.2	Shutdown	
09/04/2003	0600	35.5	184	Start-up	
	2100	6.1	32.3	Shutdown	
	2200	2.7	2415.8	Shutdown	
09/05/2003	0700	25.2	134.4	Start-up	
09/08/2003	0100	6.1	54.7	Shutdown	
	0600	14.7	69.3	Start-up	
09/12/2003	1300	9	58.8	Malfunction	M
	1400	17.1	62.9	Malfunction	M
	2300	15.7	434.8	Shutdown	
09/13/2003	0900	22.6	135.7	Start-up	
09/14/2003	0000	7	269.6	Shutdown	
	0800	8.9	516.3	Start-up	
	0900	18.6	100.9	Start-up	
09/17/2003	2300	6.3	46.9	Shutdown	
09/18/2003	0000	*	2304.2	Shutdown	
	0600	41.1	243.3	Start-up	
09/19/2003	0100	9.1	131.6	Shutdown	
	0700	17.9	335.3	Start-up	
	0800	16.7	58.2	Start-up	
	2000	7.1	66.1	Shutdown	
09/20/2003	0700	15.2	446.1	Start-up	
	0800	27.2	153.7	Start-up	
09/21/2003	0100	15.4	324.9	Shutdown	
	0800	22	112.8	Start-up	
09/22/2003	0000	7.9	150.8	Shutdown	
	0700	33.7	424.1	Start-up	
	0800	14.5	54.7	Start-up	
09/24/2003	2300	18.6	265.8	Shutdown	
09/25/2003	0600	34.5	338.2	Start-up	
	0700	12.4	33.5	Start-up	
09/27/2003	0000	40.3	703.4	Shutdown	
	0800	35.4	363.2	Start-up	
	0900	16.5	49.7	Start-up	
09/28/2003	0000	18	345.8	Shutdown	
	0800	33.7	314	Start-up	
	0900	15.3	42.5	Start-up	
09/30/2003	0000	10.3	135.9	Shutdown	
	0700	23.6	361.7	Start-up	
	0800	16	49.8	Start-up	

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

malfunction - 3

* Data not excluded.

BAYSIDE POWER STATION - CT 1A
MONITOR DOWNTIME - QUARTER 3, 2003

Date	Hours of Missing Data for Monitor Downtime	Reason for Monitor Downtime
07/01/2003	1	Calibrate CO Monitor
08/18/2003	3	Aborted Linearity
09/10/2003	2	CO Monitor failed Calibration/ Re-calibration

Monitor availability:	99.67%

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1A
MAINTENANCE/REPAIR OF CEMS - QUARTER 3, 2003

Date	Unusual Maint. Or Repair of CEMS
	No Unusual Maintenance of CEMS

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

NOx: 40 CFR 75, Appendix B
CO: 40 CFR 60, Appendix F

RATA data required pursuant to these CFRs

MONITORING DATA CHECKING SOFTWARE 4.1 BETA **05/28/2003**

TEST SUMMARY REPORT PAGE 1

ORIS Code: 7873 State: FL
Facility Name: BAYSIDE County: HILLSBOROUGH

Unit/ Stack ID	Comp/Sys	Sys Parm	Comp Type	Test Type	End Date	Hour/ Time	Test #	Load Lvls	Reason	Reported Test Result	Recalculated Test Result
CT1A	/113	NOX		RATA (RT 610-616)	04/23/2003	1519	1	1	C	Pass-APS	Pass-APS

MONITORING DATA CHECKING SOFTWARE 4.1 BETA 05/28/2003

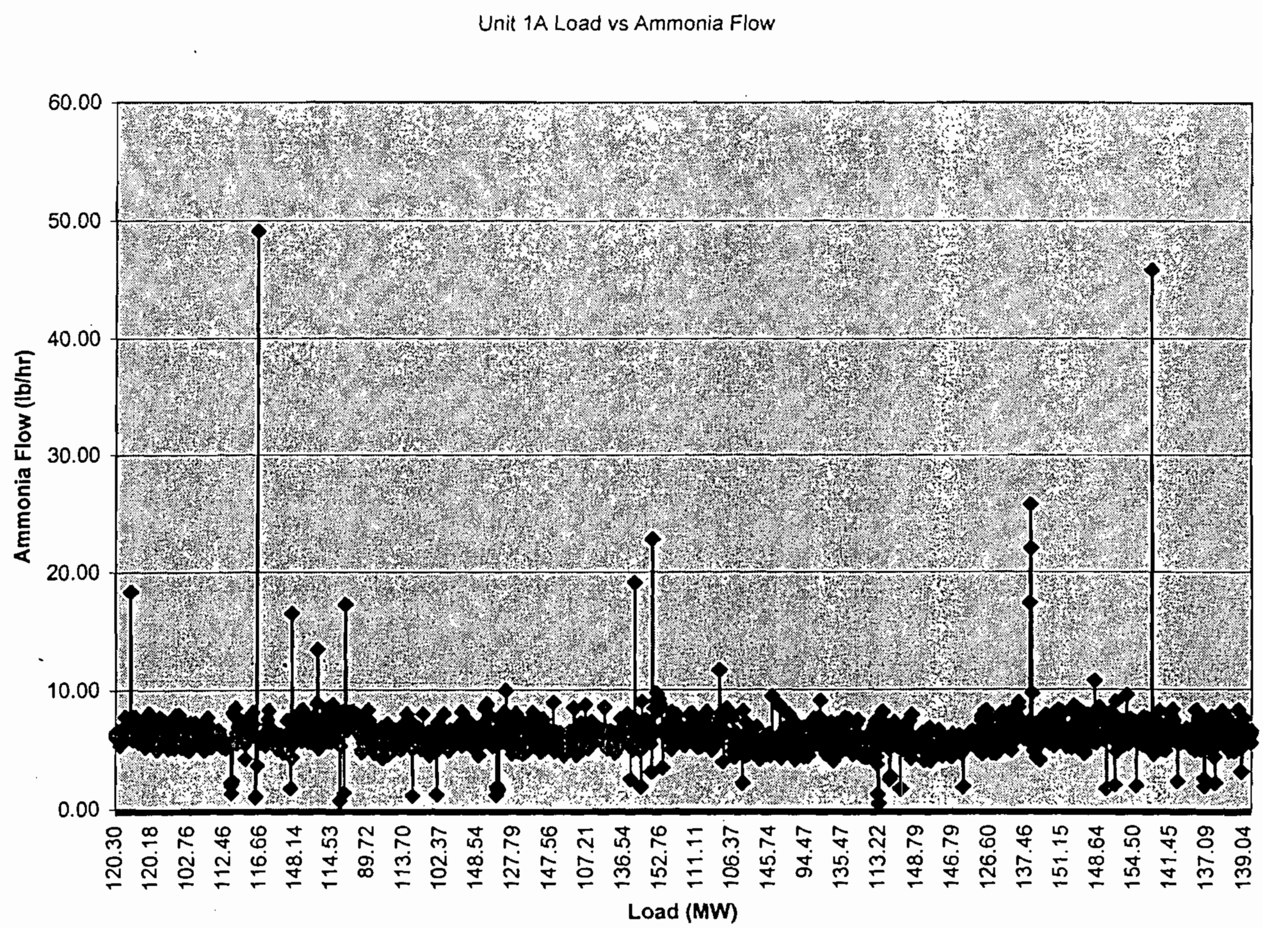
RATA REPORT (RT 610/611) PAGE 2

ORIS Code: 7873 Facility: BAYSIDE State: FL
Unit/Stack ID: CT1A System ID: 113 Parameter: NOX
Test End Date/Time: 04/23/2003 1519 Test No.: 1 # of Operating Levels: 1 Units of Measure: LB/MMBTU
Reason for Test: C
Performance Spec: <= 10.0% Next RATA: Four Op Qtrs
Recalc. Results: Pass-APS % RA:12.77 Mean Diff: 0.001 BAF: 1.111
Reported Results: Pass-APS % RA:12.77 Mean Diff: 0.001 BAF: 1.111

Operating Level: H

Run	Start Date	Start Time	End Date	End Time	Run Status	Reference Method	Monitoring Value	Gross Load or Velocity
1	04/23/2003	1023	04/23/2003	1044	1	0.012	0.011	162
2	04/23/2003	1054	04/23/2003	1115	1	0.012	0.011	162
3	04/23/2003	1128	04/23/2003	1149	1	0.012	0.011	161
4	04/23/2003	1212	04/23/2003	1233	1	0.012	0.011	160
5	04/23/2003	1247	04/23/2003	1308	1	0.013	0.011	160
6	04/23/2003	1323	04/23/2003	1344	1	0.012	0.011	159
7	04/23/2003	1355	04/23/2003	1416	1	0.012	0.011	158
8	04/23/2003	1427	04/23/2003	1448	1	0.012	0.011	158
9	04/23/2003	1458	04/23/2003	1519	1	0.013	0.011	157

Summary Statistics	Reported	Recalculated
Mean of Monitoring System	0.011	0.011
Mean of Reference Method Values	0.012	0.012
Mean of Difference	0.001	0.001
Standard Deviation of Difference	0.000	0.000
Confidence Coefficient	0.000	0.000
T-Value	2.306	2.306
Relative Accuracy:	12.77	12.77
Bias Adjustment Factor	1.111	1.111
APS Flag	1	1
Indicator of Normal Op. Level	N	N
Gross Unit Load or Velocity	160	160
Reference Method Used	7e,3a	



Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 24

SUMMARY REPORT – NO_x EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE NSPS SUBPART GG

Pollutant: NOx - Combustion Turbine

Emission Limitation: 3.5 ppmvd @ 15% O_2 on a 24-hour block average

Reporting period dates: From 07/01/03 to 12/31/03

Company: Tampa Electric Company
Address: P.O. Box 111
Tampa, FL 33601-0111

Monitor Manufacturer and Model No.: Thermal Environmental 42CLS

Date of Latest CMS Certification or Audit: October 2003

Process Unit Description : 169 MW Combined Cycle Combustion Turbine (CT 1B)

Total source operating time in reporting period[1]: 3201.75

Emission Data Summary[1]		CMS Performance Summary[2]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown	210	a. Monitor equipment malfunctions	0
b. Control equipment problems	0	b. Non-Monitor equipment malfunctions	9
c. Process problems	0	c. Quality assurance calibration	0
d. Other known causes	0	d. Other known causes	0
e. Unknown causes	0	e. Unknown causes	0
2. Total duration of excess emission	210	2. Total CMS Downtime	9
3. Total duration of excess emissions x (100) / Total source operating time	7 %	3. Total CMS Downtime x (100) / Total source operating time	0 %

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.

This form is used for reporting excess emission according to New Source Performance Standard (NSPS) Subpart GG only. (CO is not a regulated by Subpart GG and is reported under the semi-annual excess emission report required by Section III, permit condition 25.)

1. For gases record all times in hours.

2. 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 60.7(c) shall be submitted.

   TEC Note: The summary report form and the excess emission report required will also be submitted in the semi-annual report.

Per Title V Permit #0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1B
24 - HOUR BLOCK AVERAGE - QUARTER 3, 2003

Date	24-hour block CO	24-hour block NOx
07/01/2003	1.1	3.2
07/02/2003	1.1	3.0
07/03/2003	1.3	3.1
07/04/2003	1.1	3.0
07/05/2003	1.1	3.0
07/06/2003	1.1	3.0
07/07/2003	1.0	3.2
07/08/2003	1.1	3.0
07/09/2003	1.2	3.1
07/10/2003	0.9	3.0
07/11/2003	0.9	3.0
07/12/2003	1.0	3.0
07/13/2003	0.9	3.0
07/14/2003	1.0	2.9
07/15/2003	0.9	3.0
07/16/2003	1.0	3.1
07/17/2003	1.2	3.3
07/18/2003	0.9	3.1
07/19/2003	Offline	Offline
07/20/2003	0.0	0.0
07/21/2003	1.0	3.0
07/22/2003	1.0	3.0
07/23/2003	1.0	3.0
07/24/2003	1.0	3.0
07/25/2003	1.0	3.0
07/26/2003	1.0	3.0
07/27/2003	1.0	3.0
07/28/2003	1.0	3.0
07/29/2003	1.1	3.5
07/30/2003	1.0	2.9
07/31/2003	1.0	3.0
08/01/2003	1.1	3.0
08/02/2003	1.0	3.0
08/03/2003	Offline	Offline
08/04/2003	1.3	3.3
08/05/2003	1.1	3.0
08/06/2003	1.1	3.0
08/07/2003	1.1	3.0
08/08/2003	1.1	2.9
08/09/2003	1.2	2.9
08/10/2003	1.1	3.0
08/11/2003	1.2	3.0
08/12/2003	1.2	3.0
08/13/2003	1.2	3.0
08/14/2003	1.2	3.0
08/15/2003	1.2	3.0
08/16/2003	1.2	2.9
08/17/2003	1.4	3.2
08/18/2003	1.3	2.9

08/19/2003	1.3	2.9
08/20/2003	1.3	3.1
08/21/2003	1.3	2.9
08/22/2003	Offline	Offline
08/23/2003	0.7	3.0
08/24/2003	0.6	3.0
08/25/2003	0.7	2.9
08/26/2003	0.9	2.7
08/27/2003	0.7	3.0
08/28/2003	0.7	3.0
08/29/2003	0.8	3.0
08/30/2003	0.7	2.9
08/31/2003	0.7	2.9
09/01/2003	0.7	2.9
09/02/2003	0.7	2.9
09/03/2003	0.8	2.9
09/04/2003	0.8	3.1
09/05/2003	Offline	Offline
09/06/2003	0.7	2.9
09/07/2003	0.8	3.3
09/08/2003	0.8	2.9
09/09/2003	0.9	2.9
09/10/2003	0.8	2.9
09/11/2003	0.9	3.0
09/12/2003	1.1	2.9
09/13/2003	1.0	2.9
09/14/2003	0.9	3.1
09/15/2003	1.0	2.9
09/16/2003	0.9	3.0
09/17/2003	1.0	2.9
09/18/2003	1.0	2.9
09/19/2003	1.0	2.9
09/20/2003	1.0	2.9
09/21/2003	1.0	3.0
09/22/2003	1.0	2.9
09/23/2003	1.0	3.0
09/24/2003	1.1	2.9
09/25/2003	1.1	2.9
09/26/2003	1.1	2.9
09/27/2003	1.7	3.0
09/28/2003	1.3	3.3
09/29/2003	1.1	2.9
09/30/2003	1.1	2.9

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1B
EXCLUDED DATA - QUARTER 3, 2003

Date	Hours Data Excluded	NOx Value of Excluded Data	CO Value of Excluded Data	Reason for Exclusion
07/01/2003	2300	*	39.1	Shutdown
	2400	*	2358.8	Shutdown
07/02/2003	0600	24.4	237.9	Start-up
07/03/2003	2300	24.8	1211.7	Shutdown
07/04/2003	0900	31	166	Start-up
07/06/2003	2200	7.2	68.8	Shutdown
07/07/2003	0900	38.8	391.6	Start-up
	2200	16.8	216.5	Shutdown
07/08/2003	0700	21.5	234	Start-up
07/10/2003	0100	36.9	1211.5	Shutdown
	0700	24.3	175.7	Start-up
07/13/2003	0100	9.8	115.1	Shutdown
	1000	25.6	151.9	Start-up
07/14/2003	0200	*	263.8	Shutdown
	0600	12.2	74.4	Start-up
07/16/2003	2200	*	44.7	Shutdown
	2300	10.1	2337.6	Shutdown
07/17/2003	0800	20	636.8	Start-up/Shutdown
	1100	33.4	410.2	Start-up
	2200	6.7	83	Shutdown
07/18/2003	1200	31.3	332.2	Start-up
	1300	27.6	100.4	Start-up
	1800	6.6	155.1	Shutdown
07/20/2003	1900	29.1	520.7	Start-up/ Shutdown
07/21/2003	0800	51.5	261	Start-up
	0900	44.5	632.1	Start-up
	1000	18.2	109.1	Start-up
08/02/2003	2200	17.1	503.5	Shutdown
08/04/2003	0700	43.5	379.2	Start-up
08/16/2003	2200	6.9	170.1	Shutdown
08/17/2003	0900	39.5	470.9	Start-up
	1000	10	*	Start-up
	2300	*	70	Shutdown
08/18/2003	0800	36	297.4	Start-up
	2200	21.9	414.3	Shutdown
08/19/2003	0700	45.5	341.2	Start-up
08/20/2003	2300	*	34.8	Shutdown
	2400	*	2236.8	Shutdown
08/21/2003	0900	37.1	544.4	Start-up
	1000	12.4	36.4	Start-up
	1700	7.3	91.9	Shutdown
08/23/2003	1100	42.6	372.4	Start-up
	1200	28	115.7	Start-up
	2400	14.6	403.9	Shutdown
08/24/2003	0900	19.8	467.2	Start-up
	1000	19	74.3	Start-up
	2300	19.4	723.5	Shutdown
08/25/2003	0600	40.6	452.8	Start-up

	0700	13.8	29.5	Start-up
	2200	9.4	164.8	Shutdown
08/26/2003	0900	22.8	150.7	Start-up
	2400	10.7	151.6	Shutdown
08/27/2003	0900	12.8	490	Start-up
	1000	20.1	126.6	Start-up
09/04/2003	2100	*	224.2	Shutdown
09/06/2003	0900	32.5	464	Start-up
	1000	24.2	163.4	Start-up
09/07/2003	0200	*	71.2	Shutdown
	0900	18.6	140	Start-up
	2400	14.5	413.7	Shutdown
09/08/2003	0700	14.2	119.7	Start-up
09/09/2003	0100	6.5	73.4	Shutdown
	0700	15.6	239.4	Start-up
09/10/2003	2300	10.5	330.6	Shutdown
09/11/2003	0700	26.5	140.2	Start-up
09/12/2003	0100	41.9	1099.6	Shutdown
	0700	46.1	301.6	Start-up
	0800	50.4	312.1	Start-up
	0900	*	10.4	Start-up
09/13/2003	2300	*	67.9	Shutdown
09/14/2003	0700	*	617.8	Start-up
	0800	18.5	96.6	Start-up
	2400	24.7	427.1	Shutdown
09/15/2003	0400	8.6	454.8	Start-up
	0500	60	86.7	Start-up
	2400	14.4	657	Shutdown
09/16/2003	0600	25.6	173.3	Start-up
	2400	34.6	949.1	Shutdown
09/17/2003	0600	34	462.3	Start-up
	0700	13.7	57.1	Start-up
09/18/2003	2400	6.8	68.1	Shutdown
09/19/2003	0600	11.1	467.7	Start-up
	0700	14.2	62.1	Start-up
09/20/2003	2200	20	349.5	Shutdown
09/21/2003	0800	*	341.5	Start-up
	0900	20.5	101.6	Start-up
	2300	*	48	Shutdown
	2400	*	2310.3	Shutdown
09/22/2003	0700	19.8	191.5	Start-up
	2400	36.4	606	Shutdown
09/23/2003	0500	40.4	335.1	Start-up
	2300	25	426.3	Shutdown
09/24/2003	0600	36.3	246.6	Start-up
09/25/2003	2300	24.3	419.3	Shutdown
09/26/2003	0600	33.4	551.2	Start-up
	0700	20.6	48.5	Start-up
	2300	40	612.6	Shutdown
09/27/2003	0800	35.8	235.3	Start-up
	2400	35.1	1392.3	Shutdown
09/28/2003	0700	41.5	343.4	Start-up

	2300	18.5	445.3	Shutdown
09/29/2003	0600	24.9	192.8	Start-up
	2300	19.3	581.8	Shutdown
09/30/2003	0600	21.3	534.5	Start-up
	0700	14.3	64.1	Start-up
	2200	8.5	114.6	Shutdown

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

* Data not excluded.

BAYSIDE POWER STATION - CT 1B
MAINTENANCE/REPAIR OF CEMS - QUARTER 3, 2003

Date	Unusual Maint. Or Repair of CEMS
	No Unusual Maintenance of CEMS

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1B
MONITOR DOWNTIME - QUARTER 3, 2003

Date	Hours of Missing Data for Monitor Downtime	Reason for Monitor Downtime
08/23/2003	9	Calibration bottles valved out

Monitor availability:	97%

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

NOx: 40 CFR 75, Appendix B RATA data required pursuant to these CFRs
CO: 40 CFR 60, Appendix F
Date RATA data

MONITORING DATA CHECKING SOFTWARE 4.1 BETA **05/28/2003**
TEST SUMMARY REPORT PAGE 1

ORIS Code: 7873 State: FL
Facility Name: BAYSIDE County: HILLSBOROUGH

Unit/ Stack ID	Comp/Sys	Sys Parm	Comp Type	Test Type	Hour/ End Date	Test Time	Load #	Lvls	Reason	Reported Test Result	Recalculated Test Result
CT1B	/213	NOX		RATA (RT 610-616)	04/17/2003	1209	1	1	C	Pass-APS	Pass-APS

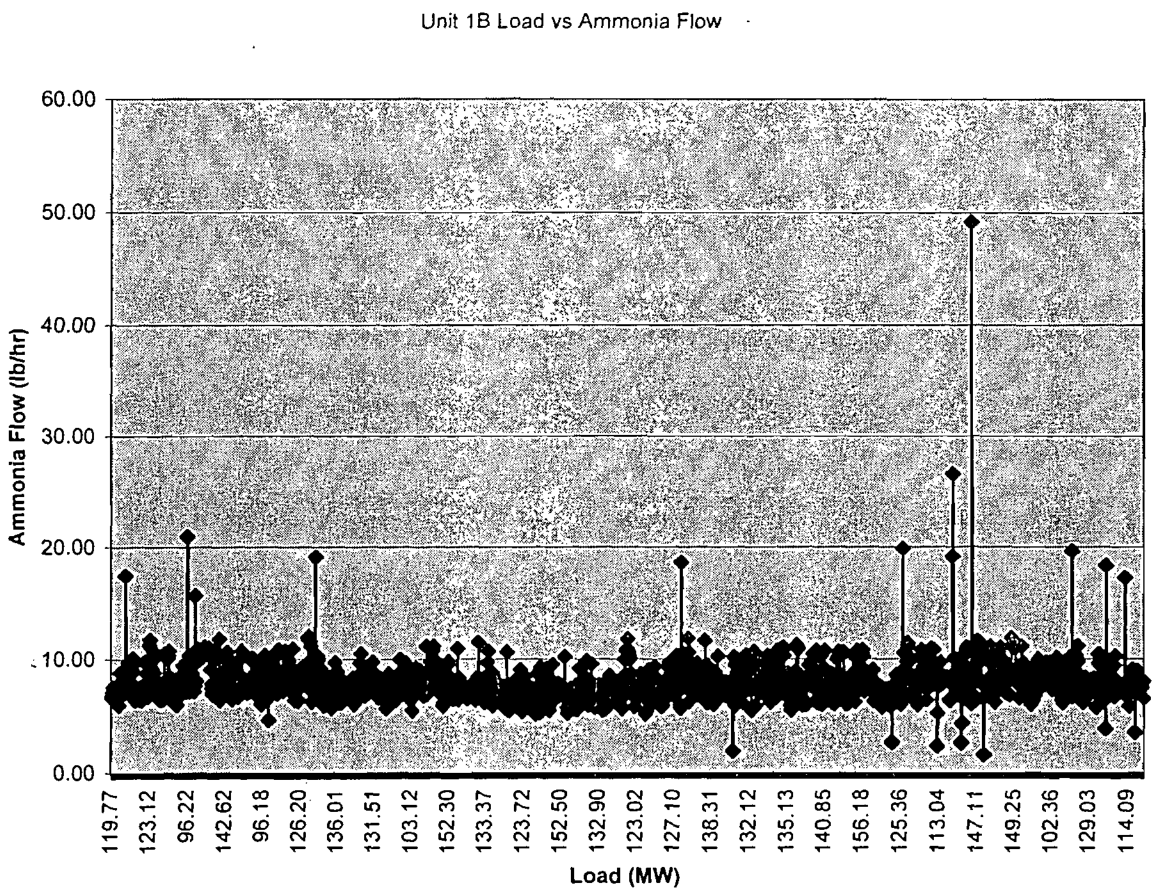
MONITORING DATA CHECKING SOFTWARE 4.1 BETA 05/28/2003
RATA REPORT (RT 610/611) PAGE 2

ORIS Code: 7873 Facility: BAYSIDE State: FL
Unit/Stack ID: CT1B System ID: 213 Parameter: NOX
Test End Date/Time: 04/17/2003 1209 Test No.: 1 # of Operating Levels: 1 Units of Measure: LB/MMBTU
Reason for Test: C
Performance Spec: <= 10.0% Next RATA: Four Op Qtrs
Recalc. Results: Pass-APS % RA: 9.09 Mean Diff: 0.001 BAF: 1.100
Reported Results: Pass-APS % RA: 9.09 Mean Diff: 0.001 BAF: 1.100

Operating Level: H

Run	Start Date	Start Time	End Date	End Run Time	Status	Reference Method	Monitoring Value	Gross Load or Velocity
1	04/17/2003	0702	04/17/2003	0723	1	0.011	0.010	164
2	04/17/2003	0736	04/17/2003	0757	1	0.011	0.010	163
3	04/17/2003	0809	04/17/2003	0830	1	0.011	0.010	162
4	04/17/2003	0850	04/17/2003	0911	1	0.011	0.010	160
5	04/17/2003	0923	04/17/2003	0944	1	0.011	0.010	160
6	04/17/2003	1000	04/17/2003	1021	1	0.011	0.010	159
7	04/17/2003	1035	04/17/2003	1056	1	0.011	0.010	158
8	04/17/2003	1116	04/17/2003	1137	1	0.011	0.010	157
9	04/17/2003	1148	04/17/2003	1209	1	0.011	0.010	157

Summary Statistics	Reported	Recalculated
Mean of Monitoring System	0.010	0.010
Mean of Reference Method Values	0.011	0.011
Mean of Difference	0.001	0.001
Standard Deviation of Difference	0.000	0.000
Confidence Coefficient	0.000	0.000
T-Value	2.306	2.306
Relative Accuracy:	9.09	9.09
Bias Adjustment Factor	1.100	1.100
APS Flag	1	1
Indicator of Normal Op. Level	N	N
Gross Unit Load or Velocity	160	160
Reference Method Used	7e,3a	



Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 24

SUMMARY REPORT – NO_x EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE NSPS SUBPART GG

Pollutant: NOx - Combustion Turbine

Emission Limitation: 3.5 ppmvd @ 15% O_2 on a 24-hour block average

Reporting period dates: From 07/01/03 to 07/31/03

Company: Tampa Electric Company
Address: P.O. Box 111
Tampa, FL 33601-0111

Monitor Manufacturer and Model No.: Thermal Environmental 42CLS

Date of Latest CMS Certification or Audit: October 2003

Process Unit Description : 169 MW Combined Cycle Combustion Turbine (CT 1C)

Total source operating time in reporting period[1]: 3428.25

Emission Data Summary[1]		CMS Performance Summary[2]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown	230	a. Monitor equipment malfunctions	0
b. Control equipment problems	0	b. Non-Monitor equipment malfunctions	0
c. Process problems	5	c. Quality assurance calibration	0
d. Other known causes	0	d. Other known causes	0
e. Unknown causes	0	e. Unknown causes	0
2. Total duration of excess emission	235	2. Total CMS Downtime	0
3. Total duration of excess emissions x (100) / Total source operating time	7 %	3. Total CMS Downtime x (100) / Total source operating time	0%

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.

This form is used for reporting excess emission according to New Source Performance Standard (NSPS) Subpart GG only. (CO is not a regulated by Subpart GG and is reported under the semi-annual excess emission report required by Section III, permit condition 25.)

1. For gases record all times in hours.

2. 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 60.7(c) shall be submitted.

   TEC Note: The summary report form and the excess emission report required will also be submitted in the semi-annual report.

Per Title V Permit #0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1C
24 - HOUR BLOCK AVERAGE - QUARTER 3, 2003

Date	24-hour block CO	24-hour block NOx
07/01/2003	0.7	3.0
07/02/2003	0.8	3.1
07/03/2003	0.8	3.3
07/04/2003	1.5	3.1
07/05/2003	0.7	3.0
07/06/2003	0.7	3.0
07/07/2003	0.7	3.0
07/08/2003	0.7	3.0
07/09/2003	0.7	3.0
07/10/2003	0.7	3.0
07/11/2003	0.7	3.0
07/12/2003	0.8	3.0
07/13/2003	0.7	3.0
07/14/2003	0.7	3.0
07/15/2003	0.9	3.0
07/16/2003	0.8	3.0
07/17/2003	0.8	3.0
07/18/2003	Offline	Offline
07/19/2003	Offline	Offline
07/20/2003	0.0	0.0
07/21/2003	0.9	3.1
07/22/2003	0.8	3.0
07/23/2003	0.9	3.0
07/24/2003	0.8	3.0
07/25/2003	0.9	3.0
07/26/2003	0.8	3.0
07/27/2003	0.8	3.0
07/28/2003	0.8	3.0
07/29/2003	0.9	3.0
07/30/2003	0.8	3.0
07/31/2003	0.9	3.0
08/01/2003	0.9	3.0
08/02/2003	0.9	3.0
08/03/2003	0.9	3.0
08/04/2003	0.9	3.0
08/05/2003	0.9	3.0
08/06/2003	0.9	3.0
08/07/2003	0.9	3.0
08/08/2003	0.9	2.9
08/09/2003	0.9	2.9
08/10/2003	0.9	3.0
08/11/2003	0.9	3.0
08/12/2003	0.9	3.1
08/13/2003	0.9	3.0
08/14/2003	0.9	3.0
08/15/2003	1.0	2.9
08/16/2003	0.9	2.9
08/17/2003	1.1	2.9
08/18/2003	0.8	2.9

08/19/2003	0.7	3.2
08/20/2003	0.5	2.9
08/21/2003	0.6	2.9
08/22/2003	0.5	2.9
08/23/2003	0.6	2.7
08/24/2003	0.6	3.0
08/25/2003	0.6	2.9
08/26/2003	2.1	3.5
08/27/2003	0.6	2.9
08/28/2003	0.6	2.9
08/29/2003	0.7	2.9
08/30/2003	0.6	2.9
08/31/2003	0.6	2.9
09/01/2003	0.6	2.9
09/02/2003	0.7	3.1
09/03/2003	1.2	2.7
09/04/2003	0.8	2.9
09/05/2003	0.7	2.9
09/06/2003	0.6	2.9
09/07/2003	0.7	2.9
09/08/2003	0.7	3.0
09/09/2003	0.8	2.9
09/10/2003	0.8	2.9
09/11/2003	0.8	3.0
09/12/2003	0.8	2.9
09/13/2003	0.8	2.9
09/14/2003	0.8	2.9
09/15/2003	0.8	2.9
09/16/2003	0.8	2.9
09/17/2003	0.8	2.9
09/18/2003	0.9	2.9
09/19/2003	0.8	2.9
09/20/2003	0.8	2.9
09/21/2003	0.8	2.9
09/22/2003	0.8	2.9
09/23/2003	0.9	3.1
09/24/2003	0.8	2.9
09/25/2003	0.8	2.9
09/26/2003	0.8	2.9
09/27/2003	0.8	2.9
09/28/2003	0.9	2.9
09/29/2003	0.8	2.9
09/30/2003	0.9	2.9

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1C
EXCLUDED DATA - QUARTER 3, 2003

Date	Hours Data Excluded	NOx Value of Excluded Data	CO Value of Excluded Data	Reason for Exclusion
07/01/2003	0800	14.9	139.8	Start-up
07/03/2003	0100	31.2	1066.9	Shutdown
	0800	35.2	362.3	Start-up
07/04/2003	2300	35	1582.7	Shutdown
07/05/2003	1000	25.7	115.8	Start-up
	2100	6.7	59.5	Shutdown
07/06/2003	1000	38.8	390.7	Start-up
	1100	18.5	49.5	Start-up
07/07/2003	2300	47.8	672.8	Shutdown
07/08/2003	0800	37.1	255.9	Start-up
	2200	16.4	346.1	Shutdown
07/09/2003	1600	32.8	363.1	Start-up
	1700	36.6	195.5	Start-up
07/14/2003	2300	36.4	525.6	Shutdown
07/15/2003	0800	17	81.2	Start-up
07/17/2003	2400	7.3	264.2	Shutdown
07/20/2003	1100	29.7	427.4	Start-up
	1200	45.8	511.4	Shutdown
	2000	34	297	Cold Steam Turbine Start-up
	2100	56.8	185.8	Cold Steam Turbine Start-up
	2200	58.1	182.9	Cold Steam Turbine Start-up
	2300	57.1	190.8	Cold Steam Turbine Start-up
	2400	52.8	182.7	Cold Steam Turbine Start-up
07/21/2003	2300	15.3	421.3	Shutdown
07/22/2003	0700	23.2	160.5	Start-up
07/23/2003	1400	13	108.5	Cold Steam Turbine Start-up
	1500	32.3	308.2	Cold Steam Turbine Start-up
	1600	35.4	349.5	Cold Steam Turbine Start-up
	1700	9.9	12	Cold Steam Turbine Start-up
07/25/2003	2200	8.5	96	Shutdown
07/26/2003	0900	35.8	448.7	Start-up
	1000	20.3	44.6	Start-up
07/27/2003	2400	9.1	111.8	Shutdown
07/28/2003	0800	22.4	149.8	Start-up
07/29/2003	2400	15.7	722.9	Shutdown
07/30/2003	0900	40.4	299.5	Start-up
08/01/2003	2300	8.9	105.8	Shutdown
08/02/2003	0800	25.6	435.9	Start-up
	0900	15	53.2	Start-up
	2300	16.9	572.1	Shutdown
08/03/2003	1100	22.6	488	Start-up
	1200	22.1	88.3	Start-up
08/07/2003	2300	6.7	69.3	Shutdown
08/08/2003	0800	34.1	215.3	Start-up
08/09/2003	0100	29	501.4	Shutdown
	0900	21.5	104.2	Start-up
	2300	8.7	303.8	Shutdown
08/10/2003	1000	28	252.8	Start-up

08/11/2003	0100	6.2	61.1	Shutdown
	0700	5.6	151.8	Start-up
	2400	6.5	66.3	Shutdown
08/12/2003	0600	*	549.1	Start-up
	0700	13	51.2	Start-up
	2400	12.1	144.7	Shutdown
08/13/2003	0600	30.5	379.3	Start-up
	0700	9.7	26.1	Start-up
08/14/2003	2100	8	252.6	Shutdown
08/15/2003	0800	28.3	197.8	Start-up
	2400	30.7	506.9	Shutdown
08/16/2003	0700	34	503.9	Start-up
	0800	8.5	17.3	Start-up
08/18/2003	2100	21.7	342.2	Shutdown
08/19/2003	0600	39.7	357.8	Start-up
	2300	27.7	430.1	Shutdown
08/20/2003	0900	36.1	503.2	Start-up
	1000	13.2	19.8	Start-up
08/21/2003	2300	14.8	694.4	Shutdown
08/22/2003	1000	25.6	174.3	Start-up
08/23/2003	0500	14.1	140.2	Malfunction
	0600	27.9	250.9	Malfunction
	0700	28	268.3	Malfunction
	0800	28.7	265.9	Malfunction
	0900	29.1	195.4	Malfunction
08/24/2003	2400	7.9	80.1	Shutdown
08/25/2003	0900	24.3	162.5	Start-up
	2300	8	89.4	Shutdown
08/26/2003	1000	*	391.3	Start-up
	1100	11.8	2.7	Start-up
08/27/2003	2400	17.2	317.7	Shutdown
08/28/2003	0600	18	129.1	Start-up
	2200	6.3	65.8	Shutdown
08/29/2003	0800	36.7	181.7	Start-up
	2400	8.9	99.5	Shutdown
08/30/2003	0900	27.2	498.1	Start-up
	1000	18.1	52.4	Start-up
08/31/2003	2400	18.9	255.1	Shutdown
09/01/2003	0900	38.6	427	Start-up
	1000	10.9	16.6	Start-up
	2400	10.5	126.6	Shutdown
09/02/2003	0800	*	141.2	Start-up
	0900	15.5	78.6	Start-up
	2200	12.6	165.2	Shutdown
09/03/2003	0700	23.6	596	Start-up
	0800	39.7	1372.1	Shutdown
	1100	18.9	91	Start-up
	2200	18.3	300	Shutdown
09/04/2003	0700	20	501	Start-up
	0800	15	56.2	Start-up
09/06/2003	0100	21.9	363.6	Shutdown
	0700	19.3	255.8	Start-up

09/08/2003	2400	*	56.2	Shutdown
09/09/2003	0100	*	2510.8	Shutdown
	1000	23.1	136.6	Start-up
09/10/2003	2400	9.1	187.3	Shutdown
09/11/2003	0500	*	530.9	Start-up
	0600	*	93.2	Start-up
09/12/2003	2400	15.8	576.5	Shutdown
09/13/2003	0900	32.2	424.5	Start-up
	1000	22.1	96.9	Start-up
09/15/2003	0100	20.3	311.5	Shutdown
	0600	25.3	138.2	Start-up
09/16/2003	0200	36.2	616	Shutdown
	0700	20.3	133.7	Start-up
09/17/2003	0200	25.7	427	Shutdown
	0600	26.1	208.5	Start-up
09/19/2003	2100	22.2	378.2	Shutdown
09/20/2003	0800	16.2	631.5	Start-up
	0900	23.7	122.8	Start-up
09/23/2003	0100	13.5	559.8	Shutdown
	0600	30.2	436.2	Start-up
09/24/2003	0100	24.8	420.5	Shutdown
	0700	22.8	124	Start-up
09/26/2003	0100	16.1	859.9	Shutdown
	0800	*	17.2	Start-up
	0900	23.6	104.7	Start-up
09/28/2003	2400	6.4	40.8	Shutdown
09/29/2003	0100	10.4	2533.1	Shutdown
	0700	38.7	409.6	Start-up
	0800	12.4	30.8	Start-up

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1C
MAINTENANCE/REPAIR OF CEMS - QUARTER 3, 2003

Date	Unusual Maint. Or Repair of CEMS
	No Unusual Maintenance of CEMS

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1C
MONITOR DOWNTIME - QUARTER 3, 2003

Date	Hours of Missing Data for Monitor Downtime	Reason for Monitor Downtime

Monitor availability:	100%

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

1404 total hours

NOx: 40 CFR 75, Appendix B RATA data required pursuant to these CFRs
CO: 40 CFR 60, Appendix F
Date RATA data

MONITORING DATA CHECKING SOFTWARE 4.1 BETA **05/28/2003**
TEST SUMMARY REPORT PAGE 1

ORIS Code: 7873 State: FL
Facility Name: BAYSIDE County: HILLSBOROUGH

Unit/ Stack ID	Comp/Sys	Sys Parm	Comp Type	Test Type	End Date	Hour/ Time	Test #	Load Lvls	Reason	Reported Test Result	Recalculated Test Result
CT1C	/313	NOX		RATA (RT 610-616)	04/18/2003	1110	1	1	C	Pass-APS	Pass-APS

MONITORING DATA CHECKING SOFTWARE 4.1 BETA 05/28/2003
RATA REPORT (RT 610/611) PAGE 2

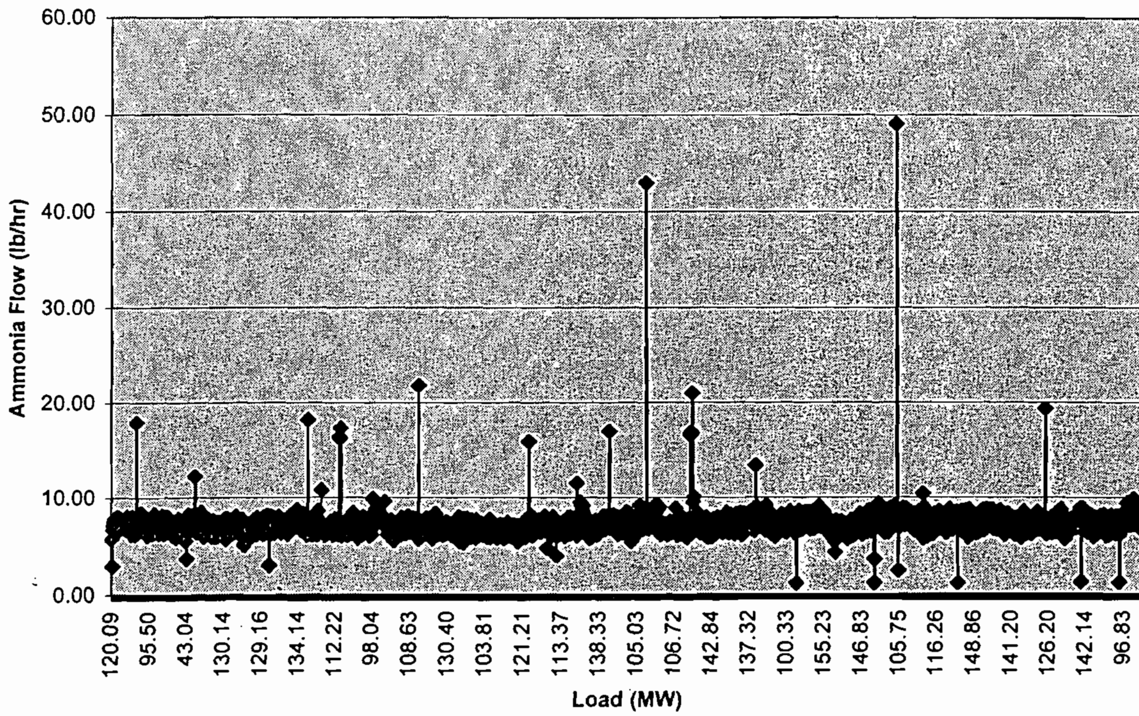
ORIS Code: 7873 Facility: BAYSIDE State: FL
Unit/Stack ID: CT1C System ID: 313 Parameter: NOX
Test End Date/Time: 04/18/2003 1110 Test No.: 1 # of Operating Levels: 1 Units of Measure: LB/MMBTU
Reason for Test: C
Performance Spec: <= 10.0% Next RATA: Four Op Qtrs
Recalc. Results: Pass-APS % RA:16.97 Mean Diff: 0.002 BAF: 1.111
Reported Results: Pass-APS % RA:16.97 Mean Diff: 0.002 BAF: 1.111

Operating Level: H

Run	Start Date	Start Time	End Date	End Time	Run Status	Reference Method	Monitoring Value	Gross Load or Velocity
1	04/18/2003	0601	04/18/2003	0622	1	0.011	0.010	168
2	04/18/2003	0652	04/18/2003	0713	1	0.012	0.010	168
3	04/18/2003	0725	04/18/2003	0746	1	0.012	0.010	167
4	04/18/2003	0757	04/18/2003	0818	1	0.012	0.010	165
5	04/18/2003	0830	04/18/2003	0851	1	0.012	0.010	163
6	04/18/2003	0904	04/18/2003	0925	1	0.012	0.010	162
7	04/18/2003	0941	04/18/2003	1002	1	0.011	0.010	161
8	04/18/2003	1014	04/18/2003	1035	1	0.011	0.010	160
9	04/18/2003	1049	04/18/2003	1110	1	0.011	0.010	159

Summary Statistics	Reported	Recalculated
Mean of Monitoring System	0.010	0.010
Mean of Reference Method Values	0.012	0.012
Mean of Difference	0.002	0.002
Standard Deviation of Difference	0.001	0.001
Confidence Coefficient	0.000	0.000
T-Value	2.306	2.306
Relative Accuracy:	16.97	16.97
Bias Adjustment Factor	1.111	1.111
APS Flag	1	1
Indicator of Normal Op. Level	N	N
Gross Unit Load or Velocity	164	164
Reference Method Used	7e,3a	

Unit 1C Load vs Ammonia Flow



Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 24

ATTACHMENT 3

BAYSIDE POWER STATION - CT 1A
24 - HOUR BLOCK AVERAGE - QUARTER 4, 2003

Date	24-hour block CO	24-hour block NOx
10/01/2003	0.5	2.9
10/02/2003	0.3	2.9
10/03/2003	0.2	3.0
10/04/2003	Offline	Offline
10/05/2003	Offline	Offline
10/06/2003	Offline	Offline
10/07/2003	1.5	2.9
10/08/2003	1.3	2.9
10/09/2003	0.4	3.1
10/10/2003	0.2	2.9
10/11/2003	0.2	2.9
10/12/2003	0.3	2.9
10/13/2003	0.3	2.9
10/14/2003	0.3	2.9
10/15/2003	1.3	2.9
10/16/2003	1.3	2.9
10/17/2003	1.4	2.9
10/18/2003	2.2	2.9
10/19/2003	0.7	2.9
10/20/2003	0.7	2.9
10/21/2003	0.8	2.8
10/22/2003	0.8	2.9
10/23/2003	0.8	2.9
10/24/2003	0.9	2.9
10/25/2003	0.9	2.9
10/26/2003	0.9	2.9
10/27/2003	1.0	2.9
10/28/2003	0.9	2.9
10/29/2003	1.0	2.9
10/30/2003	1.0	2.9
10/31/2003	1.0	2.9
11/01/2003	1.0	2.9
11/02/2003	1.4	3.0
11/03/2003	Offline	Offline
11/04/2003	0.0	0.0
11/05/2003	0.0	0.0
11/06/2003	1.1	2.9
11/07/2003	0.9	2.9
11/08/2003	0.9	2.9
11/09/2003	0.9	2.9
11/10/2003	0.9	2.9
11/11/2003	0.4	2.9
11/12/2003	0.2	3.0
11/13/2003	0.2	1.9
11/14/2003	0.3	2.5
11/15/2003	0.3	2.9
11/16/2003	0.4	2.9
11/17/2003	0.4	3.2
11/18/2003	0.4	2.9

11/19/2003	0.4	2.8
11/20/2003	0.5	3.2
11/21/2003	0.5	2.9
11/22/2003	1.1	3.1
11/23/2003	0.5	2.9
11/24/2003	0.7	3.4
11/25/2003	0.6	3.0
11/26/2003	0.7	3.0
11/27/2003	0.6	2.9
11/28/2003	0.5	2.9
11/29/2003	0.7	2.9
11/30/2003	0.6	2.9
12/01/2003	0.7	2.9
12/02/2003	0.7	2.9
12/03/2003	0.7	3.0
12/04/2003	0.6	2.9
12/05/2003	0.7	3.0
12/06/2003	0.8	2.9
12/07/2003	0.9	2.9
12/08/2003	0.9	2.9
12/09/2003	0.9	2.9
12/10/2003	0.8	2.9
12/11/2003	0.8	2.9
12/12/2003	0.9	2.9
12/13/2003	0.9	2.9
12/14/2003	0.8	2.9
12/15/2003	Offline	Offline
12/16/2003	Offline	Offline
12/17/2003	Offline	Offline
12/18/2003	Offline	Offline
12/19/2003	Offline	Offline
12/20/2003	Offline	Offline
12/21/2003	0.0	0.0
12/22/2003	Offline	Offline
12/23/2003	1.1	2.9
12/24/2003	1.2	2.9
12/25/2003	1.1	2.9
12/26/2003	1.2	2.9
12/27/2003	1.3	2.9
12/28/2003	0.0	0.0
12/29/2003	1.2	3.0
12/30/2003	1.2	3.1
12/31/2003	1.3	2.9

Per Air Permit No. 0570040-015-AC, Section III, Specifi

BAYSIDE POWER STATION - CT 1A
EXCLUDED DATA - QUARTER 4, 2003

Date	Hours Data Excluded	NOx Value of Excluded Data	CO Value of Excluded Data	Reason for Exclusion
10/02/2003	0000	17.3	348.2	Shutdown
	0700	16.9	230.6	Start-up
	0800	16.9	26.1	Start-up
	2200	9.4	104.6	Shutdown
10/03/2003	1000	42.1	111.2	Start-up
	2100	38.8	942.0	Shutdown
10/07/2003	0600	45.8	*	Start-up
	0700	54.3	*	Start-up
	0900	15.5	19.4	Start-up
	2400	27.3	364.5	Shutdown
10/08/2003	0600	17.2	473.2	Start-up
	0700	18.5	92.4	Start-up
	2200	9.7	177.2	Shutdown
10/09/2003	0600	*	35.1	Start-up
	0700	22.3	113.5	Start-up
10/13/2003	0100	29.6	433.4	Shutdown
	0600	25.0	153.9	Start-up
10/14/2003	0100	29.6	433.4	Shutdown
	0600	25.0	153.9	Start-up
10/15/2003	0200	46.2	243.1	Malfunction
10/16/2003	2200	9.2	99.2	Shutdown
10/17/2003	0500	48.4	153.4	Start-up
	2300	5.9	20.1	Shutdown
10/18/2003	0700	15.2	428.4	Start-up
	0800	24.1	80.4	Start-up
10/19/2003	0000	9.6	103.6	Shutdown
	0600	33.9	156.7	Start-up
10/20/2003	2300	11.0	132.8	Shutdown
10/21/2003	0400	5.7	474.3	Start-up
	0500	30.4	179.2	Start-up
10/26/2003	1000	35.4	281.6	Start-up
10/29/2003	2300	8.7	148.6	Shutdown
10/30/2003	1100	28.4	145.5	Start-up
	2100	15.0	505.2	Shutdown
10/31/2003	1300	44.8	316.2	Start-up
	1400	26.3	61.7	Start-up
	1500	7.1	*	tuning
	1600	7.0	*	tuning
	1700	5.2	*	tuning
	2000	7.0	269.3	Shutdown
11/01/2003	0700	11.6	577.9	Start-up
	0900	36.5	216.4	Start-up
11/02/2003	0100	7.2	79.2	Shutdown
	0900	43.5	319.9	Start-up
	1000	19.9	*	Start-up
11/04/2003	1900	32.6	401.1	Start-up/ Shutdown
11/05/2003	1400	41.6	260.4	tuning
	1500	48.9	189.1	tuning
	1600	50.3	185.2	tuning
	1700	50.1	213.7	tuning
	1800	49.9	215.6	tuning
	1900	49.8	218.8	tuning
	2000	49.3	219.4	tuning
	2100	49	220.3	tuning
	2200	49.6	218.2	tuning
11/06/2003	0100	50.3	215.7	tuning
	0200	49.9	218.9	tuning
	0300	51.5	212.7	tuning
	0400	51.2	217.6	tuning
	0500	48.2	280.4	tuning
	0600	26.9	100.1	tuning

	0800	22.4	296.6	tuning
	1500	22.4	136.1	Start-up
	2200	13.2	196.9	Shutdown
11/07/2003	1000	13.5	586.5	Start-up
	1100	24.4	76.9	Start-up
11/09/2003	1700	21.7	312	Shutdown
11/10/2003	0900	36.6	254.8	Start-up
	2300	10.8	176.9	Shutdown
11/11/2003	0600	25.2	136.8	Start-up
11/12/2003	0000	9.9	213.3	Shutdown
	1000	38.1	194.5	Start-up
	2300	15.2	661.7	Shutdown
11/13/2003	0800	33.7	372.1	Start-up
	0900	20.8	90.5	Start-up
11/17/2003	0100	9.9	98.8	Shutdown
	0600	48.3	348.7	Start-up
11/18/2003	2300	13.4	190.4	Shutdown
11/19/2003	0700	23.5	129.3	Start-up
	2300	7.1	65.4	Shutdown
11/20/2003	0500	46.2	314.3	Start-up
11/21/2003	2200	6.8	64	Shutdown
11/22/2003	0700	23.6	448.6	Start-up
	0800	33.6	186.9	Start-up
	2300	27	1358.4	Shutdown
11/23/2003	0800	25.6	118.4	Start-up
11/24/2003	0000	14.7	194.4	Shutdown
	0700	42.9	396.3	Start-up
11/25/2003	0000	6.6	66.9	Shutdown
	0600	12.6	518.5	Start-up
	0700	12.2	120.7	Start-up
11/26/2003	0100	41.9	1095.3	Shutdown
	0600	40.4	462.7	Start-up
	0700	15.8	53.7	Start-up
11/27/2003	0000	8.9	90.5	Shutdown
	0800	*	80.2	Start-up
	0900	26.6	158.6	Start-up
11/28/2003	0800	23.6	463.8	Start-up
	0900	29.3	203.8	Start-up
12/02/2003	0100	8.8	156.7	Shutdown
	0600	*	192.1	Start-up
	0700	26.3	109.8	Start-up
12/04/2003	0000	11.3	130.3	Shutdown
	0600	43.3	245.8	Start-up
12/05/2003	0200	10	240.6	Shutdown
	0600	27	414.1	Start-up
	0700	17.7	89.6	Start-up
12/09/2003	0200	12.2	151.8	Shutdown
	0700	41.8	237.4	Start-up
12/14/2003	1900	15.8	182.7	Shutdown
12/21/2003	0200	52.1	295.9	Shutdown
	0300	54.5	376.2	Shutdown
12/23/2003	0600	19.6	435.7	Start-up
	0700	40	221.9	Start-up
12/26/2003	2300	8.2	101.7	Shutdown
12/27/2003	0600	42	470.7	Start-up
	0700	33.1	177.5	Start-up
	1100	5.3	32	Shutdown
12/28/2003	0100	8.1	2403.3	Shutdown
12/29/2003	1000	45.2	426.6	Start-up
12/30/2003	0100	13.2	663.1	Shutdown
	0600	39.4	377.7	Start-up
	0700	22.8	77.4	Start-up
	2200	*	157.2	Shutdown
12/31/2003	0600	46	250.1	Start-up
	1100	15.3	160.2	Shutdown
	1800	31.5	146.3	Start-up

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

* Data not excluded.

BAYSIDE POWER STATION - CT 1A
MAINTENANCE/REPAIR OF CEMS - QUARTER 4, 2003

Date	Unusual Maint. Or Repair of CEMS
10/18/2003	Replaced Umbilical on Unit 1A CEM System

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1A
MONITOR DOWNTIME - QUARTER 4, 2003

Date	Hours of Missing Data for Monitor Downtime	Reason for Monitor Downtime
10/07/2003	3	CO Monitor failed Calibration/ Re-calibration
10/10/2003	2	CO Monitor failed Calibration/ Re-calibration
10/14/2003	14	CO Monitor failed Calibration/ Re-calibration
10/15/2003	14	CO calibration monitor problems
10/18/2003	7	Replaced Umbilical on Unit 1A CEM System

Monitor availability:	97.37%

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR75 - APPENDIX A
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-1A
Test Date: 11/21/03

Run	Run Times		Unit	Air Services Group - Test Data			Continuous Emissions Monitor	Difference	Run
				RM - 7E NO_x	RM - 3A O_2	RM - 19 NO_x	RM - 19 NO_x		
Number	Start	Stop	Load	ppmvd	%v, dry	lbs/mmBtu	lbs/mmBtu	lbs/mmbtu	Flag
1	11:07	11:39	160	3.75	14.18	0.012	0.011	0.001	1
2	11:51	12:12	159	3.78	14.29	0.012	0.011	0.001	1
3	12:21	12:42	159	3.78	14.29	0.012	0.011	0.001	1
4	12:50	13:11	158	3.78	14.31	0.012	0.011	0.001	1
5	13:19	13:40	158	3.78	14.31	0.012	0.011	0.001	1
6	13:48	14:09	157	3.88	14.31	0.013	0.011	0.002	1
7	14:19	14:40	157	3.78	14.32	0.012	0.011	0.001	1
8	14:50	15:11	157	3.78	14.32	0.012	0.011	0.001	1
9	15:18	15:39	157	3.78	14.32	0.012	0.011	0.001	1
		Means:	158			0.012	0.011	0.001	

Standard Deviation of Differences:	0.000
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.000
Relative Accuracy (RA), Calculated Against Mean Reference Method Value:	11.29
Relative Accuracy (RA), Calculated As Mean Difference, Alternative Performance Specification (APS):	0.001
Bias Test:	FAILED
Bias Adjustment Factor (BAF):	1.101
Alternative Bias Adjustment Factor (BAF):	N/A

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR75 - APPENDIX A
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-1A
Test Date: 11/21/03

Run Number	Run Times Start	Stop	Unit Load	Air Services Group - Test Data RM - 3A CO_2, % volume dry	Continuous Emissions Monitor CO_2, % volume dry	Difference CO_2, % volume dry	Run Flag
1	11:07	11:39	160	3.95	4.161	-0.211	1
2	11:51	12:12	159	3.96	4.162	-0.202	1
3	12:21	12:42	159	3.98	4.162	-0.182	1
4	12:50	13:11	158	3.97	4.157	-0.187	1
5	13:19	13:40	158	3.98	4.156	-0.176	1
6	13:48	14:09	157	3.95	4.150	-0.200	1
7	14:19	14:40	157	3.95	4.148	-0.198	1
8	14:50	15:11	157	3.95	4.140	-0.190	1
9	15:18	15:39	157	3.95	4.140	-0.190	1
		Means:	158	3.960	4.153	-0.193	

Standard Deviation of Differences:	0.011
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.008
Relative Accuracy (RA):	5.08

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR60 - APPENDIX B, PERFORMANCE SPECIFICATION 4
RELATIVE ACCURACY TEST AUDIT

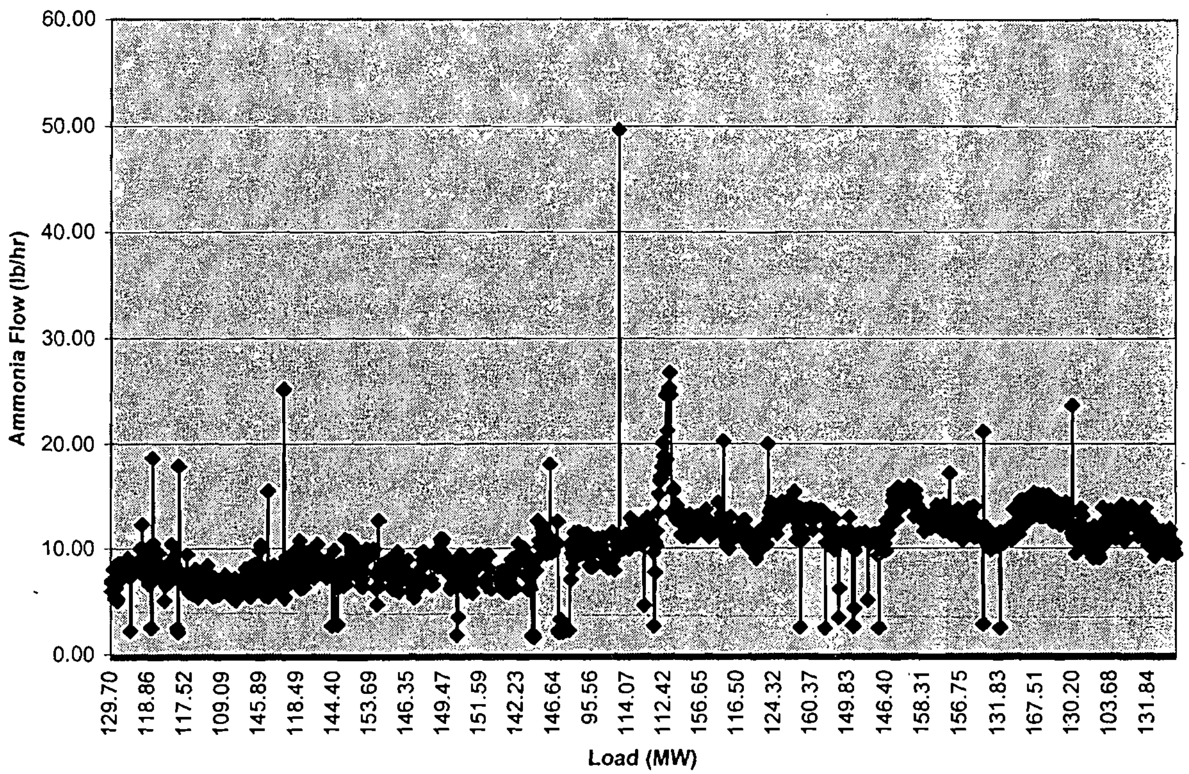
Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-1A
Test Date: 11/21/03

Applicable Standard: 7.8 ppmvd CO @ 15% O_2

Run Number	Run Times Start	Run Times Stop	Unit Load	Air Services Group - Test Data: RM -10 CO ppmvd	RM - 3A O_2 %v, dry	CO ppmvd @ 15% O_2	Continuous Emissions Monitor: CO ppmvd	CO ppmvd @ 15% O_2	Difference: CO ppmvd @ 15% O_2	Run Flag
1	11:07	11:39	160	0.64	14.18	0.559	0.60	0.500	0.059	1
2	11:51	12:12	159	0.77	14.29	0.691	0.60	0.500	0.191	1
3	12:21	12:42	159	0.69	14.29	0.614	0.60	0.495	0.119	1
4	12:50	13:11	158	0.70	14.31	0.626	0.60	0.491	0.135	1
5	13:19	13:40	158	0.69	14.31	0.617	0.60	0.486	0.131	1
6	13:48	14:09	157	0.77	14.31	0.693	0.60	0.491	0.202	1
7	14:19	14:40	157	0.76	14.32	0.683	0.60	0.500	0.183	1
8	14:50	15:11	157	0.84	14.32	0.757	0.60	0.495	0.262	1
9	15:18	15:39	157	0.84	14.32	0.757	0.60	0.495	0.262	1
		Means:	158			0.666		0.495	0.172	

Standard Deviation of Differences:	0.067	
Number of Valid Runs Included in Data Set:	9	
t-value for Data Set:	2.306	
2.5% Error Confidence Coefficient (CC) for Data Set:	0.052	
Relative Accuracy (RA), Calculated Against Mean Reference Method Value:	33.51	%
Relative Accuracy (RA), Calculated Against Applicable Standard:	2.86	%

Unit 1A Load vs Ammonia Flow



Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 24

BAYSIDE POWER STATION - CT 1B
24 - HOUR BLOCK AVERAGE - QUARTER 4, 2003

Date	24-hour block CO	24-hour block NOx
10/01/2003	1.6	3.0
10/02/2003	1.2	3.1
10/03/2003	1.9	3.0
10/04/2003	1.2	3.0
10/05/2003	1.2	2.9
10/06/2003	1.3	2.9
10/07/2003	1.3	3.0
10/08/2003	1.2	2.9
10/09/2003	1.2	3.1
10/10/2003	1.2	2.9
10/11/2003	1.2	3.0
10/12/2003	1.2	2.9
10/13/2003	1.2	2.9
10/14/2003	1.2	2.9
10/15/2003	1.2	2.9
10/16/2003	1.2	2.9
10/17/2003	1.3	3.0
10/18/2003	1.3	2.9
10/19/2003	1.2	2.9
10/20/2003	1.3	2.9
10/21/2003	1.3	3.0
10/22/2003	1.2	2.9
10/23/2003	1.3	2.9
10/24/2003	1.3	2.9
10/25/2003	1.7	3.2
10/26/2003	1.3	2.9
10/27/2003	1.3	2.9
10/28/2003	1.2	3.0
10/29/2003	1.3	2.9
10/30/2003	1.3	2.9
10/31/2003	1.3	2.9
11/01/2003	1.3	2.9
11/02/2003	1.3	2.9
11/03/2003	1.4	2.9
11/04/2003	1.6	3.0
11/05/2003	1.4	2.9
11/06/2003	1.4	2.9
11/07/2003	1.5	3.1
11/08/2003	1.6	3.1
11/09/2003	1.4	3.0
11/10/2003	1.1	2.9
11/11/2003	0.7	2.9
11/12/2003	0.7	2.9
11/13/2003	0.7	3.0
11/14/2003	0.7	2.9
11/15/2003	0.9	2.9
11/16/2003	0.8	2.9
11/17/2003	0.8	2.9
11/18/2003	0.8	2.9

11/19/2003	0.8	2.9
11/20/2003	0.8	2.9
11/21/2003	0.9	2.9
11/22/2003	0.8	2.9
11/23/2003	0.9	2.9
11/24/2003	0.8	2.9
11/25/2003	0.9	2.9
11/26/2003	0.9	2.9
11/27/2003	1.0	2.9
11/28/2003	0.9	2.9
11/29/2003	1.0	3.2
11/30/2003	0.9	2.9
12/01/2003	1.0	2.9
12/02/2003	1.0	2.9
12/03/2003	0.9	2.9
12/04/2003	0.9	2.9
12/05/2003	1.0	3.0
12/06/2003	1.1	2.9
12/07/2003	1.1	2.9
12/08/2003	1.1	2.9
12/09/2003	1.2	2.9
12/10/2003	Offline	Offline
12/11/2003	Offline	Offline
12/12/2003	Offline	Offline
12/13/2003	Offline	Offline
12/14/2003	Offline	Offline
12/15/2003	Offline	Offline
12/16/2003	Offline	Offline
12/17/2003	Offline	Offline
12/18/2003	Offline	Offline
12/19/2003	Offline	Offline
12/20/2003	Offline	Offline
12/21/2003	Offline	Offline
12/22/2003	Offline	Offline
12/23/2003	1.2	2.9
12/24/2003	0.0	5.0
12/25/2003	Offline	Offline
12/26/2003	1.2	2.9
12/27/2003	1.2	2.9
12/28/2003	1.5	2.9
12/29/2003	1.6	2.9
12/30/2003	Offline	Offline
12/31/2003	1.3	2.9

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1B
EXCLUDED DATA - QUARTER 4, 2003

Date	Hours Data Excluded	NOx Value of Excluded Data	CO Value of Excluded Data	Reason for Exclusion
10/01/2003	0600	32.6	217.4	Start-up
	2400	26.2	1445.5	Shutdown
10/02/2003	0500	21.6	151.4	Start-up
	2300	*	47.2	Shutdown
	2400	*	2256	Shutdown
10/03/2003	0700	35.1	446.6	Start-up
	0800	13.5	*	Start-up
	2300	40.1	791.3	Shutdown
10/04/2003	0600	*	216.4	Start-up
	0700	34.9	157	Start-up
10/07/2003	0100	*	41.6	Shutdown
	0200	*	2282.3	Shutdown
	0500	43.1	446.6	Start-up
	0600	10.4	*	Start-up
10/08/2003	2300	9.3	165.8	Shutdown
10/09/2003	0600	36	286.8	Start-up
	2300	*	64.8	Shutdown
10/10/2003	0600	*	100.8	Start-up
	0700	17.2	110.4	Start-up
	2200	*	17.1	Shutdown
	2300	35.8	1476.9	Shutdown
10/11/2003	0800	*	14.2	Start-up
	0900	2.4	91.6	Start-up
	2200	8.8	165.8	Shutdown
10/12/2003	0700	40.1	388.1	Start-up
	0800	36.8	10.8	Start-up
	2300	20	879.9	Shutdown
10/13/2003	0600	34.1	440.4	Start-up
	0700	17.1	56.5	Start-up
	2400	9.3	118.6	Shutdown
10/14/2003	0500	16.9	610.7	Start-up
	0600	18.1	65	Start-up
	2200	19.6	352.4	Shutdown
10/15/2003	0500	*	4	Start-up
	0600	20.2	82.2	Start-up
	2300	34.1	430.7	Shutdown
10/16/2003	0500	12.5	426.7	Start-up
	0600	28	99.1	Start-up
	2100	9.1	101.9	Shutdown
10/17/2003	0400	27.3	411.6	Start-up
	0500	13.4	57.1	Start-up
10/18/2003	0100	32.5	1116.9	Shutdown
	0700	45.7	239.9	Start-up
10/19/2003	0100	21.4	350.1	Shutdown
	0800	16.6	493.1	Start-up
	0900	15.9	49.2	Start-up
10/20/2003	0100	12.2	167.8	Shutdown
	0600	27.7	398.8	Start-up

	0700	14.9	51.2	Start-up
10/21/2003	2300	45.3	1032.6	Shutdown
10/22/2003	0600	19.6	607.6	Start-up
	0700	20.5	75.1	Start-up
	2100	6.5	65	Shutdown
10/23/2003	0700	42.3	424.8	Start-up
	0800	20.9	69.9	Start-up
	2300	10.1	155.6	Shutdown
10/24/2003	0600	42.5	287.2	Start-up
	0700	24.3	98.2	Start-up
	2300	16.3	399.9	Shutdown
10/25/2003	0800	34.5	178.2	Start-up
	2400	6.7	227.4	Shutdown
10/26/2003	0900	20.7	112.6	Start-up
	2400	8	140.7	Shutdown
10/27/2003	0600	43.1	211.4	Start-up
	2400	*	32.5	Shutdown
10/28/2003	0100	*	1916.6	Shutdown
	0600	21.2	108.2	Start-up
	2300	18.7	276.7	Shutdown
10/29/2003	1100	39.5	157.1	Start-up
	2400	11.7	147.7	Shutdown
10/30/2003	0700	*	462.8	Start-up
	0800	27.6	73.3	Start-up
	2200	7.3	261.9	Shutdown
10/31/2003	0900	36.9	440.7	Start-up
	1000	15.1	18.3	Start-up
11/01/2003	2100	7.1	180.6	Shutdown
11/03/2003	1200	42.6	311.8	Start-up
	1300	28.7	89.1	Start-up
	2200	6.5	257	Shutdown
11/04/2003	1200	29.2	176	Start-up
	2400	12.5	384.7	Shutdown
11/05/2003	1300	15.3	142.5	Start-up
11/08/2003	0100	7.5	86	Shutdown
	0900	30.3	475.9	Start-up
11/09/2003	0100	8.9	383	Shutdown
	1000	41.6	488.8	Start-up
	1100	15.3	113.2	Start-up
	2000	11.6	132.1	Shutdown
11/10/2003	1000	37.6	201.9	Start-up
	1100	12.1	96.1	Start-up
11/13/2003	2200	29.9	343.3	Shutdown
11/14/2003	0700	50.7	333	Start-up
	0800	22.8	52.7	Start-up
11/15/2003	0100	32.6	412.1	Shutdown
	0800	21.9	103.4	Start-up
11/17/2003	2200	13.2	182.6	Shutdown
11/18/2003	1300	27.8	143.3	Start-up
11/20/2003	2300	16.2	705.7	Shutdown
11/21/2003	0500	26.5	441.6	Start-up
	0600	23.8	62.9	Start-up

	2400	11.1	145.6	Shutdown
11/22/2003	1000	29.7	452.8	Start-up
	1100	27.5	111.2	Start-up
	2400	8.6	99	Shutdown
11/23/2003	0900	23.1	508.5	Start-up
	1000	33.4	168.2	Start-up
11/24/2003	0100	7	253.3	Shutdown
	0600	14.3	451.2	Start-up
	0700	25.2	93.7	Start-up
11/29/2003	0100	12.9	151.4	Shutdown
	0600	84.7	149.2	Start-up
12/01/2003	2400	12.2	142.4	Shutdown
12/02/2003	0500	39.2	224.7	Start-up
12/04/2003	0200	9.4	364.2	Shutdown
	0700	43.1	219.1	Start-up
12/05/2003	2300	*	54.6	Shutdown
	2400	*	2231.1	Shutdown
12/06/2003	0800	41.9	416.1	Start-up
	0900	17.4	57.9	Start-up
12/08/2003	2400	8.7	163	Shutdown
12/09/2003	0600	37.8	174.2	Start-up
	2300	8.8	148.6	Shutdown
12/23/2003	0300	44.9	377.9	Start-up
	0400	35	113.3	Start-up
12/24/2003	100	7.1	167.9	Shutdown
12/26/2003	0500	41	322.1	Shutdown
	0600	76	201.7	Start-up
	1400	46.5	267.8	Start-up
12/29/2003	0100	31.5	718.8	Shutdown
	0600	32	373.9	Start-up
	0700	25.7	71.3	Start-up
	1100	18	364.9	Shutdown
12/31/2003	0900	7.8	651.2	Start-up
	1000	46.3	205.8	Start-up

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

* Data not excluded.

BAYSIDE POWER STATION - CT 1B
MAINTENANCE/REPAIR OF CEMS - QUARTER 4, 2003

Date	Unusual Maint. Or Repair of CEMS
	No Unusual Maintenance of CEMS

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1B
MONITOR DOWNTIME - QUARTER 4, 2003

Date	Hours of Missing Data for Monitor Downtime	Reason for Monitor Downtime

Monitor availability:	100%

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

NOx: 40 CFR 75, Appendix B — RATA data required pursuant to these CFRs
CO: 40 CFR 60, Appendix F
Date RATA data

MONITORING DATA CHECKING SOFTWARE 4.1 BETA **05/28/2003**
TEST SUMMARY REPORT PAGE 1

ORIS Code: 7873 State: FL
Facility Name: BAYSIDE County: HILLSBOROUGH
==

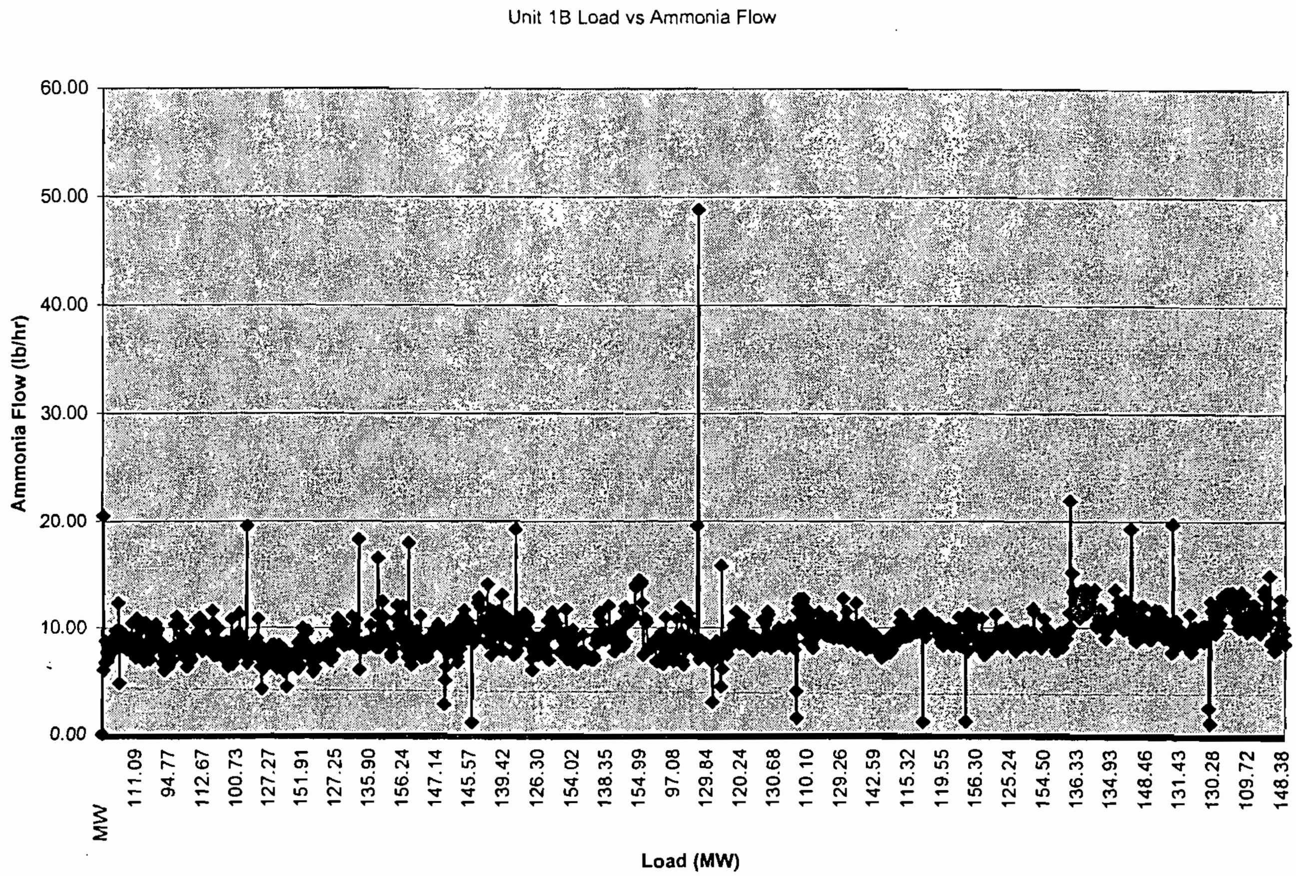
Unit/ Stack ID	Comp/Sys	Sys Parm	Comp Type	Test Type	End Date	Reported Hour/ Time	Recalculated Test #	Load Lvls	Test Reason	Test Result	Result
CT1B	/213	NOX	RATA (RT 610-616)		04/17/2003	1209	1	1	C	Pass-APS	Pass-APS

MONITORING DATA CHECKING SOFTWARE 4.1 BETA 05/28/2003
RATA REPORT (RT 610/611) PAGE 2

ORIS Code: 7873 Facility: BAYSIDE State: FL
Unit/Stack ID: CT1B System ID: 213 Parameter: NOX
Test End Date/Time: 04/17/2003 1209 Test No.: 1 # of Operating Levels: 1 Units of Measure: LB/MMBTU
Reason for Test: C
Performance Spec: <= 10.0% Next RATA: Four Op Qtrs
Recalc. Results: Pass-APS % RA: 9.09 Mean Diff: 0.001 BAF: 1.100
Reported Results: Pass-APS % RA: 9.09 Mean Diff: 0.001 BAF: 1.100
==
Operating Level: H

Run	Start Date	Start Time	End Date	End Time	Run Status	Reference Method	Monitoring Value	Gross Load or Velocity
1	04/17/2003	0702	04/17/2003	0723	1	0.011	0.010	164
2	04/17/2003	0736	04/17/2003	0757	1	0.011	0.010	163
3	04/17/2003	0809	04/17/2003	0830	1	0.011	0.010	162
4	04/17/2003	0850	04/17/2003	0911	1	0.011	0.010	160
5	04/17/2003	0923	04/17/2003	0944	1	0.011	0.010	160
6	04/17/2003	1000	04/17/2003	1021	1	0.011	0.010	159
7	04/17/2003	1035	04/17/2003	1056	1	0.011	0.010	158
8	04/17/2003	1116	04/17/2003	1137	1	0.011	0.010	157
9	04/17/2003	1148	04/17/2003	1209	1	0.011	0.010	157

Summary Statistics	Reported	Recalculated
Mean of Monitoring System	0.010	0.010
Mean of Reference Method Values	0.011	0.011
Mean of Difference	0.001	0.001
Standard Deviation of Difference	0.000	0.000
Confidence Coefficient	0.000	0.000
T-Value	2.306	2.306
Relative Accuracy:	9.09	9.09
Bias Adjustment Factor	1.100	1.100
APS Flag	1	1
Indicator of Normal Op. Level	N	N
Gross Unit Load or Velocity	160	160
Reference Method Used	7e,3a	



Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 24

BAYSIDE POWER STATION - CT 1C
24 - HOUR BLOCK AVERAGE - QUARTER 4, 2003

Date	24-hour block CO	24-hour block NOx
10/01/2003	0.9	2.9
10/02/2003	1.0	2.9
10/03/2003	0.8	2.9
10/04/2003	0.9	2.9
10/05/2003	0.9	2.9
10/06/2003	1.0	2.9
10/07/2003	1.0	2.9
10/08/2003	1.0	2.9
10/09/2003	0.9	2.9
10/10/2003	1.1	2.9
10/11/2003	1.2	3.1
10/12/2003	0.9	2.9
10/13/2003	0.9	2.9
10/14/2003	0.9	2.9
10/15/2003	0.8	2.9
10/16/2003	0.7	2.9
10/17/2003	1.0	2.9
10/18/2003	1.0	2.9
10/19/2003	1.0	2.9
10/20/2003	1.0	3.0
10/21/2003	1.0	2.8
10/22/2003	0.9	2.9
10/23/2003	1.0	2.9
10/24/2003	1.0	2.9
10/25/2003	0.9	2.9
10/26/2003	0.9	2.9
10/27/2003	1.0	2.9
10/28/2003	0.0	0.0
10/29/2003	1.0	2.9
10/30/2003	0.9	2.9
10/31/2003	0.9	3.1
11/01/2003	1.0	2.9
11/02/2003	1.0	2.9
11/03/2003	Offline	Offline
11/04/2003	0.9	2.9
11/05/2003	0.9	2.9
11/06/2003	1.0	2.9
11/07/2003	1.2	2.9
11/08/2003	1.0	2.9
11/09/2003	1.0	2.9
11/10/2003	0.7	2.9
11/11/2003	0.4	2.8
11/12/2003	0.5	2.9
11/13/2003	0.4	1.8
11/14/2003	0.5	2.9
11/15/2003	0.5	2.9
11/16/2003	0.4	2.9
11/17/2003	0.4	3.0
11/18/2003	0.6	3.1

11/19/2003	0.3	2.9
11/20/2003	0.4	2.9
11/21/2003	0.5	2.9
11/22/2003	0.5	2.9
11/23/2003	0.5	2.9
11/24/2003	0.4	2.9
11/25/2003	0.5	2.9
11/26/2003	0.6	2.9
11/27/2003	0.6	2.9
11/28/2003	0.5	2.9
11/29/2003	0.8	2.9
11/30/2003	0.5	2.9
12/01/2003	0.6	2.9
12/02/2003	0.5	2.9
12/03/2003	0.5	2.9
12/04/2003	0.5	2.9
12/05/2003	0.6	2.9
12/06/2003	0.6	2.9
12/07/2003	0.6	3.1
12/08/2003	1.1	2.9
12/09/2003	0.7	2.9
12/10/2003	0.5	2.9
12/11/2003	0.6	2.9
12/12/2003	0.7	2.9
12/13/2003	0.8	2.9
12/14/2003	0.6	3.1
12/15/2003	Offline	Offline
12/16/2003	Offline	Offline
12/17/2003	Offline	Offline
12/18/2003	Offline	Offline
12/19/2003	Offline	Offline
12/20/2003	0.0	0.0
12/21/2003	Offline	Offline
12/22/2003	0.6	2.9
12/23/2003	0.7	2.9
12/24/2003	0.7	2.9
12/25/2003	0.7	3.0
12/26/2003	0.7	2.9
12/27/2003	0.7	2.9
12/28/2003	0.7	2.9
12/29/2003	0.7	2.9
12/30/2003	0.7	2.9
12/31/2003	0.7	3.0

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1C
EXCLUDED DATA - QUARTER 4, 2003

Date	Hours Data Excluded	NOx Value of Excluded Data	CO Value of Excluded Data	Reason for Exclusion
10/01/2003	0100	16.1	889.7	Shutdown
	1000	35.5	225.8	Start-up
10/07/2003	2300	8.2	79	Shutdown
10/08/2003	0500	45.2	409.9	Start-up
	0600	11.4	33.7	Start-up
10/09/2003	2400	27.2	362.1	Shutdown
10/10/2003	0500	26.4	127.3	Start-up
10/11/2003	0100	7.3	71.3	Shutdown
	0700	44.8	404	Start-up
	0800	10.9	*	Start-up
	2400	*	31.4	Shutdown
10/12/2003	0100	19.6	1905.5	Shutdown
	0900	48.9	264.2	Start-up
10/13/2003	0100	35.5	502.9	Shutdown
	0700	39.1	438.2	Start-up
	0800	18.1	59	Start-up
10/14/2003	2200	7.3	82.3	Shutdown
10/15/2003	1000	28.5	430.7	Start-up
	1100	42.1	153.6	Start-up
	2100	13	369.4	Shutdown
10/16/2003	0700	64	253.8	Start-up
10/19/2003	2300	7.6	280.2	Shutdown
10/20/2003	0500	44.2	264.7	Start-up
	2300	7.8	84.3	Shutdown
10/21/2003	0600	44.4	240.7	Start-up
	2400	35.1	464.1	Shutdown
10/22/2003	0900	42.9	393.4	Start-up
	1000	23.9	77.3	Start-up
	2400	7.1	64.7	Shutdown
10/23/2003	0500	41.3	218.4	Start-up
	2200	7.5	59.8	Shutdown
10/24/2003	0600	19.2	160.2	Start-up
10/28/2003	0100	6.7	72.6	Shutdown
10/31/2003	2100	*	54.2	Shutdown
	2200	*	2487.9	Shutdown
11/01/2003	0800	35.3	148.7	Start-up
11/02/2003	2100	25.2	367.6	Shutdown
11/04/2003	1100	48	337.7	Start-up
	1200	27.3	95.7	Start-up
	2400	6.5	99.4	Shutdown
11/05/2003	1500	8.8	611.1	Start-up
	1600	18.6	83.9	Start-up
	1900	10.6	210.3	Shutdown
11/06/2003	0700	29	479.5	Start-up
	0800	18.6	63.6	Start-up
	2400	29	499.5	Shutdown
11/07/2003	0800	23	116.4	Start-up
	2400	14.9	522.6	Shutdown

11/08/2003	1000	32.6	230.9	Start-up
	2200	11	147.9	Shutdown
11/09/2003	0900	42.9	552.6	Start-up
	1000	16.8	77.8	Start-up
11/10/2003	2100	7.2	76.7	Shutdown
11/11/2003	1400	56.2	234.2	Start-up
	2300	7.7	79.1	Shutdown
11/12/2003	0900	31.4	163.2	Start-up
11/13/2003	0100	17.7	388.3	Shutdown
	0600	45.3	351.7	Start-up
	0700	19.2	13	Start-up
	2300	*	65.7	Shutdown
11/14/2003	1600	35.5	326.7	Start-up
	1700	24	67.7	Start-up
11/16/2003	0100	38.2	443.6	Shutdown
	0700	46.9	230.3	Start-up
11/17/2003	2200	*	17.4	Shutdown
	2300	40.4	1611.2	Shutdown
11/18/2003	0700	28.7	484.3	Start-up
	0800	24.9	86.3	Start-up
	2400	*	55.7	Shutdown
11/19/2003	0600	36.4	219.5	Start-up
11/21/2003	0100	40.3	557.4	Shutdown
	0700	36.7	143.9	Start-up
11/26/2003	0100	10.1	170.4	Shutdown
	0700	38.5	434.8	Start-up
	0800	9.8	87.7	Start-up
11/27/2003	0100	9.9	92.4	Shutdown
	0900	29.2	492.1	Start-up
	1000	19.7	69.8	Start-up
	2400	25.1	302.2	Shutdown
11/28/2003	0900	25.3	606.4	Start-up
	1000	24.4	84.3	Start-up
	2400	17.8	540	Shutdown
11/29/2003	0700	53.4	397.6	Start-up
	0800	15.6	*	Start-up
12/02/2003	2400	18	449.5	Shutdown
12/03/2003	0600	45	184.8	Start-up
12/05/2003	0100	31.2	463.5	Shutdown
	0500	35.4	416.8	Start-up
	0600	15.7	21.2	Start-up
	2300	23.5	305.3	Shutdown
12/06/2003	0800	46.9	181.2	Start-up
12/07/2003	2100	*	22.4	Shutdown
	2200	27	1455.6	Shutdown
12/08/2003	0600	55.3	433.1	Start-up
	0700	18.5	*	Start-up
12/11/2003	0100	6.2	26.6	Shutdown
	0200	21.1	1449.7	Shutdown
	0600	45.6	215.7	Start-up
12/12/2003	0100	17.9	208.6	Shutdown
	0500	38.8	157.6	Start-up

12/14/2003	2100	*	24.2	Shutdown
	2200	38.8	1371.9	Shutdown
12/20/2003	0800	27.2	537.2	Start-up
	0900	45.2	269.7	Shutdown
	1000	62.3	220.3	Start-up
	1100	43.3	1185.9	Shutdown
12/22/2003	0100	2	258.5	Cold Steam Turbine Start-up
	0200	57.1	214.1	Cold Steam Turbine Start-up
	0300	59.9	493.5	Cold Steam Turbine Start-up
	1000	51.7	467.2	Cold Steam Turbine Start-up
	1100	55.1	180.6	Cold Steam Turbine Start-up
	1200	44	168.1	Cold Steam Turbine Start-up
	1300	44.3	165.2	Cold Steam Turbine Start-up
	1400	44.8	162.8	Cold Steam Turbine Start-up
	1500	45.4	161.8	Cold Steam Turbine Start-up
	1600	45.5	522.5	Cold Steam Turbine Start-up
	1700	41.4	603.9	Cold Steam Turbine Start-up
	1800	43.4	547.4	Cold Steam Turbine Start-up
	1900	18.5	18.8	Cold Steam Turbine Start-up
12/27/2003	0100	8.5	105.2	Shutdown
	0700	39.5	394.8	Start-up
	0800	28.4	98.6	Start-up
12/31/2003	2200	*	40.8	Shutdown
	2300	*	2348	Shutdown

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1C
MAINTENANCE/REPAIR OF CEMS - QUARTER 4, 2003

Date	Unusual Maint. Or Repair of CEMS
	No Unusual Maintenance of CEMS

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 1C
MONITOR DOWNTIME - QUARTER 4, 2003

Date	Hours of Missing Data for Monitor Downtime	Reason for Monitor Downtime

Monitor availability:	100%

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

1404 total hours

NOx: 40 CFR 75, Appendix B RATA data required pursuant to these CFRs
CO: 40 CFR 60, Appendix F
Date RATA data

MONITORING DATA CHECKING SOFTWARE 4.1 BETA 05/28/2003

TEST SUMMARY REPORT PAGE 1

ORIS Code: 7873 State: FL
Facility Name: BAYSIDE County: HILLSBOROUGH

Unit/ Stack ID	Comp/Sys	Sys Parm	Comp Type	Test Type	End Date	Hour/ Time	Test #	Load Lvls	Reason	Reported Test Result	Recalculated Test Result
CT1C	/313	NOX		RATA (RT 610-616)	04/18/2003	1110	1	1	C	Pass-APS	Pass-APS

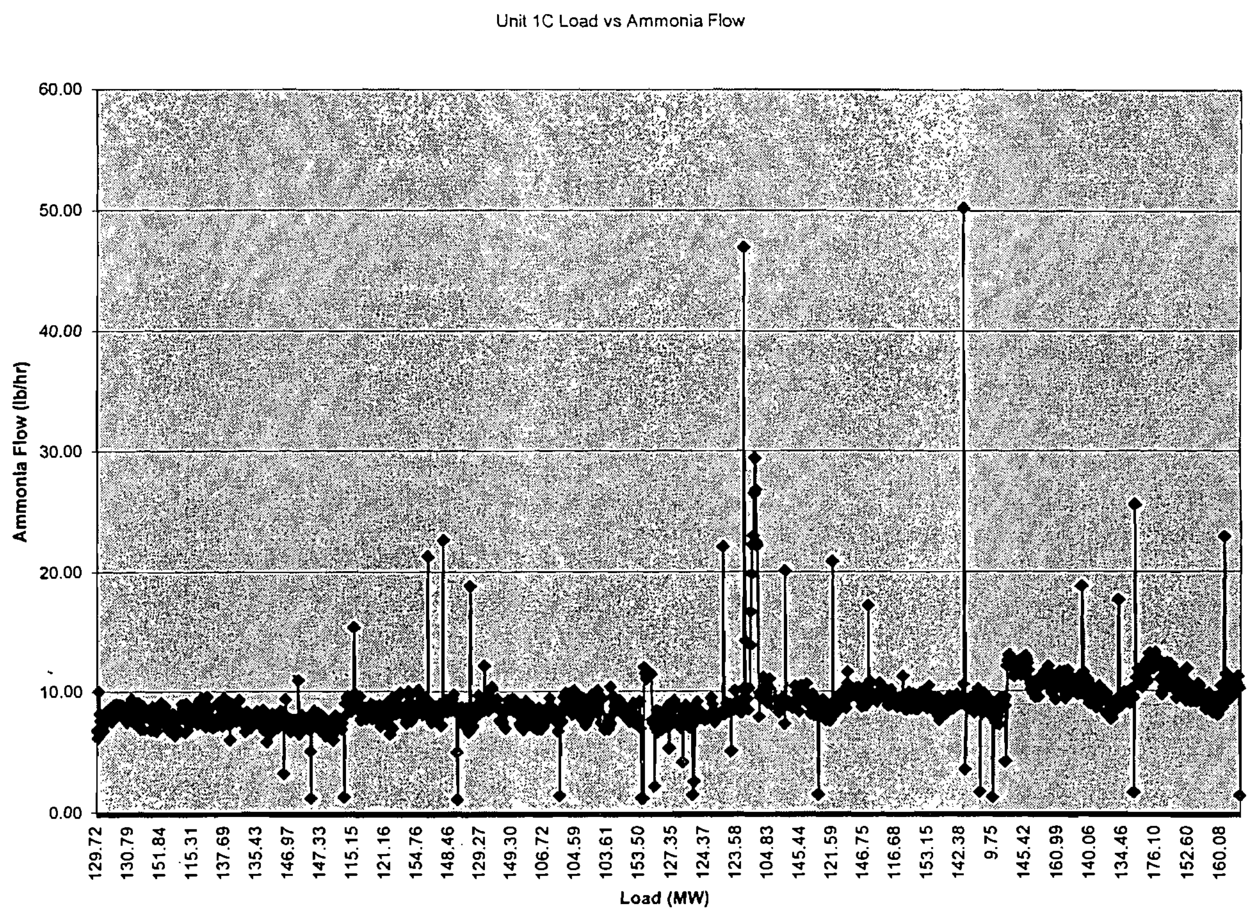
MONITORING DATA CHECKING SOFTWARE 4.1 BETA 05/28/2003
RATA REPORT (RT 610/611) PAGE 2

ORIS Code: 7873 Facility: BAYSIDE State: FL
Unit/Stack ID: CT1C System ID: 313 Parameter: NOX
Test End Date/Time: 04/18/2003 1110 Test No.: 1 # of Operating Levels: 1 Units of Measure: LB/MMBTU
Reason for Test: C
Performance Spec: <= 10.0% Next RATA: Four Op Qtrs
Recalc. Results: Pass-APS % RA:16.97 Mean Diff: 0.002 BAF: 1.111
Reported Results: Pass-APS % RA:16.97 Mean Diff: 0.002 BAF: 1.111

Operating Level: H

Run	Start Date	Start Time	End Date	End Time	Run Status	Reference Value	Monitoring Method Value	Gross Load or Velocity
1	04/18/2003	0601	04/18/2003	0622	1	0.011	0.010	168
2	04/18/2003	0652	04/18/2003	0713	1	0.012	0.010	168
3	04/18/2003	0725	04/18/2003	0746	1	0.012	0.010	167
4	04/18/2003	0757	04/18/2003	0818	1	0.012	0.010	165
5	04/18/2003	0830	04/18/2003	0851	1	0.012	0.010	163
6	04/18/2003	0904	04/18/2003	0925	1	0.012	0.010	162
7	04/18/2003	0941	04/18/2003	1002	1	0.011	0.010	161
8	04/18/2003	1014	04/18/2003	1035	1	0.011	0.010	160
9	04/18/2003	1049	04/18/2003	1110	1	0.011	0.010	159

Summary Statistics	Reported	Recalculated
Mean of Monitoring System	0.010	0.010
Mean of Reference Method Values	0.012	0.012
Mean of Difference	0.002	0.002
Standard Deviation of Difference	0.001	0.001
Confidence Coefficient	0.000	0.000
T-Value	2.306	2.306
Relative Accuracy:	16.97	16.97
Bias Adjustment Factor	1.111	1.111
APS Flag	1	1
Indicator of Normal Op. Level	N	N
Gross Unit Load or Velocity	164	164
Reference Method Used	7e,3a	



Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 24

ATTACHMENT 4

SUMMARY REPORT – NO_x EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE NSPS SUBPART GG

Pollutant: NOx - Combustion Turbine

Emission Limitation: 3.5 ppmvd @ 15% O_2 on a 24-hour block average

Reporting period dates: From 10/01/03 to 012/31/03

Company: Tampa Electric Company
Address: P.O. Box 111
Tampa, FL 33601-0111

Monitor Manufacturer and Model No.: Thermal Environmental 42CLS

Date of Latest CMS Certification or Audit: November 2003

Process Unit Description : 169 MW Combined Cycle Combustion Turbine (CT 2A)

Total source operating time in reporting period[1]: 71

Emission Data Summary[1]		CMS Performance Summary[2]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown	6	a. Monitor equipment malfunctions	0
b. Control equipment problems	0	b. Non-Monitor equipment malfunctions	0
c. Process problems	0	c. Quality assurance calibration	0
d. Other known causes	0	d. Other known causes	0
e. Unknown causes	0	e. Unknown causes	0
2. Total duration of excess emission	6	2. Total CMS Downtime	0
3. Total duration of excess emissions x (100) / Total source operating time	8 %	3. Total CMS Downtime x (100) / Total source operating time	0%

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.

This form is used for reporting excess emission according to New Source Performance Standard (NSPS) Subpart GG only. (CO is not a regulated by Subpart GG and is reported under the semi-annual excess emission report required by Section III, permit condition 25.)

1. For gases record all times in hours.

2. 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 60.7(c) shall be submitted.

   TEC Note: The summary report form and the excess emission report required will also be submitted in the semi-annual report.

Per Title V Permit #0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2A
24 - HOUR BLOCK AVERAGE - QUARTER 4, 2003

Date	24-hour block CO	24-hour block NOx
12/20/2003	1.1	3.0
12/21/2003	1.2	3.0
12/22/2003	1.2	3.1
12/23/2003	1.1	2.9
12/24/2003	Offline	Offline
12/25/2003	Offline	Offline
12/26/2003	Offline	Offline
12/27/2003	Offline	Offline
12/28/2003	Offline	Offline
12/29/2003	Offline	Offline
12/30/2003	Offline	Offline
12/31/2003	Offline	Offline

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2A
EXCLUDED DATA - QUARTER 4, 2003

Date	Hours Data Excluded	NOx Value of Excluded Data	CO Value of Excluded Data	Reason for Exclusion
12/21/2003	0800	10.9	157.7	Shutdown
12/22/2003	0800	55	457.9	Start-up
	0900	62.6	275.8	Start-up
	1000	26.1	2.6	Start-up
12/23/2003	0500	30.9	172.4	Shutdown
	0600	45.5	336.9	Start-up

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

* Data not excluded.

BAYSIDE POWER STATION - CT 2A
MAINTENANCE/REPAIR OF CEMS - QUARTER 4, 2003

Date	Unusual Maint. Or Repair of CEMS
	No Unusual Maintenance of CEMS

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2A
MONITOR DOWNTIME - QUARTER 4, 2003

Date	Hours of Missing Data for Monitor Downtime	Reason for Monitor Downtime

Monitor availability:	100.00%

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR75 - APPENDIX A
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2A
Test Date: 11/14/03

				Air Services Group - Test Data			Continuous Emissions Monitor		
Run Number	Run Times Start	Stop	Unit Load	RM - 7E NO_x ppmvd	RM - 3A O_2 %v, dry	RM - 19 NO_x lbs/mmBtu	RM - 19 NO_x lbs/mmBtu	Difference lbs/mmbtu	Run Flag
1	08:04	08:25	174	3.63	14.30	0.012	0.011	0.001	1
2	08:47	09:08	173	3.67	14.28	0.012	0.011	0.001	1
3	09:15	09:36	172	3.61	14.26	0.012	0.011	0.001	1
4	09:44	10:05	170	3.57	14.26	0.012	0.011	0.001	1
5	10:13	10:34	169	3.61	14.25	0.012	0.011	0.001	1
6	10:41	11:02	167	3.62	14.26	0.012	0.011	0.001	1
7	11:08	11:29	166	3.60	14.27	0.012	0.011	0.001	1
8	11:38	11:59	164	3.62	14.25	0.012	0.011	0.001	1
9	12:07	12:28	163	3.59	14.26	0.012	0.011	0.001	1
		Means:	169			0.012	0.011	0.001	

Standard Deviation of Differences:	0.000
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.000
Relative Accuracy (RA), Calculated Against Mean Reference Method Value:	8.33
Relative Accuracy (RA), Calculated As Mean Difference, Alternative Performance Specification (APS):	0.001
Bias Test:	FAILED
Bias Adjustment Factor (BAF):	1.091
Alternative Bias Adjustment Factor (BAF):	N/A

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR75 - APPENDIX A
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2A
Test Date: 11/14/03

Run Number	Run Times Start	Stop	Unit Load	Air Services Group - Test Data RM - 3A CO_2, % volume dry	Continuous Emissions Monitor CO_2, % volume dry	Difference CO_2, % volume dry	Run Flag
1	08:04	08:25	174	4.000	3.997	0.003	1
2	08:47	09:08	173	4.000	4.009	-0.009	1
3	09:15	09:36	172	4.020	4.013	0.007	1
4	09:44	10:05	170	4.010	4.013	-0.003	1
5	10:13	10:34	169	4.010	4.015	-0.005	1
6	10:41	11:02	167	4.010	4.020	-0.010	1
7	11:08	11:29	166	4.01	4.020	-0.010	1
8	11:38	11:59	164	4.01	4.020	-0.010	1
9	12:07	12:28	163	4.00	4.018	-0.018	1
		Means:	169	4.008	4.014	-0.006	

Standard Deviation of Differences:	0.008
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.006
Relative Accuracy (RA):	0.30

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

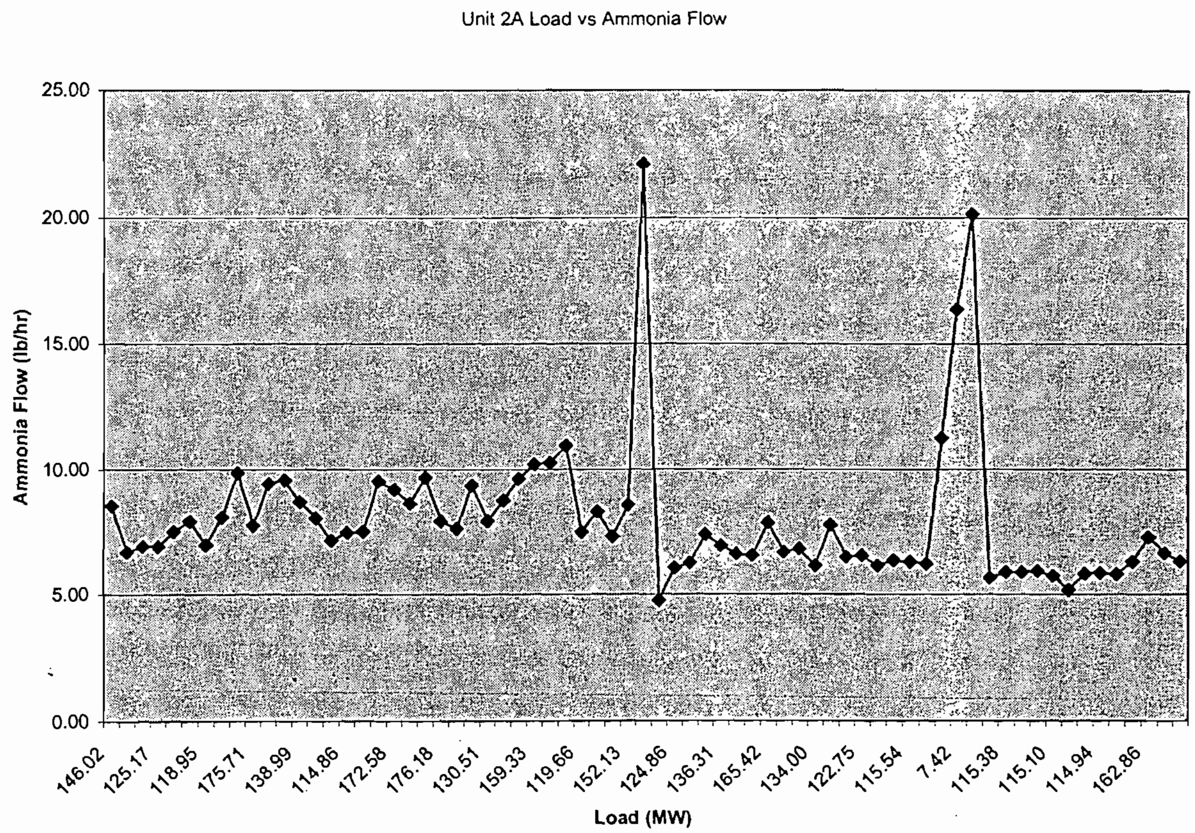
40CFR60 - APPENDIX B, PERFORMANCE SPECIFICATION 4
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2A
Test Date: 11/14/03

Applicable Standard: 7.8 ppmvd CO @ 15% O_2

				Air Services Group - Test Data			Continuous Emissions Monitor		Difference	
Run Number	Run Times Start	Run Times Stop	Unit Load	RM -10 CO ppmvd	RM - 3A O_2 %v, dry	CO ppmvd @ 15% O_2	CO ppmvd	CO ppmvd @ 15% O_2	CO ppmvd @ 15% O_2	Run Flag
1	08:04	08:25	174	0.92	14.30	0.822	0.70	0.600	0.222	1
2	08:47	09:08	173	0.90	14.28	0.802	0.70	0.600	0.202	1
3	09:15	09:36	172	0.84	14.26	0.746	0.70	0.600	0.146	1
4	09:44	10:05	170	0.86	14.26	0.764	0.70	0.600	0.164	1
5	10:13	10:34	169	0.88	14.25	0.781	0.70	0.600	0.181	1
6	10:41	11:02	167	0.86	14.26	0.764	0.70	0.600	0.164	1
7	11:08	11:29	166	0.85	14.27	0.756	0.70	0.600	0.156	1
8	11:38	11:59	164	0.86	14.25	0.763	0.69	0.590	0.173	1
9	12:07	12:28	163	0.91	14.26	0.809	0.64	0.538	0.271	1
		Means:	169			0.779		0.592	0.187	

Standard Deviation of Differences:	0.039	
Number of Valid Runs Included in Data Set:	9	
t-value for Data Set:	2.306	
2.5% Error Confidence Coefficient (CC) for Data Set:	0.030	
Relative Accuracy (RA), Calculated Against Mean Reference Method Value:	27.85	%
Relative Accuracy (RA), Calculated Against Applicable Standard:	2.78	%



Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 24

SUMMARY REPORT – NO_x EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE NSPS SUBPART GG

Pollutant: NOx - Combustion Turbine

Emission Limitation: 3.5 ppmvd @ 15% O_2 on a 24-hour block average

Reporting period dates: From 10/01/03 to 12/31/03

Company: Tampa Electric Company
Address: P.O. Box 111
Tampa, FL 33601-0111

Monitor Manufacturer and Model No.: Thermal Environmental 42CLS

Date of Latest CMS Certification or Audit: December 2003

Process Unit Description : 169 MW Combined Cycle Combustion Turbine (CT 2B)

Total source operating time in reporting period[1]: 79

Emission Data Summary[1]		CMS Performance Summary[2]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown	5	a. Monitor equipment malfunctions	0
b. Control equipment problems	0	b. Non-Monitor equipment malfunctions	0
c. Process problems	0	c. Quality assurance calibration	0
d. Other known causes	0	d. Other known causes	0
e. Unknown causes	0	e. Unknown causes	0
2. Total duration of excess emission	5	2. Total CMS Downtime	0
3. Total duration of excess emissions x (100) / Total source operating time	6 %	3. Total CMS Downtime x (100) / Total source operating time	0 %

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.

This form is used for reporting excess emission according to New Source Performance Standard (NSPS) Subpart GG only. (CO is not a regulated by Subpart GG and is reported under the semi-annual excess emission report required by Section III, permit condition 25.)

1. For gases record all times in hours.

2. 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 60.7(c) shall be submitted.

   TEC Note: The summary report form and the excess emission report required will also be submitted in the semi-annual report.

BAYSIDE POWER STATION - CT 2B
24 - HOUR BLOCK AVERAGE - QUARTER 4, 2003

Date	24-hour block CO	24-hour block NOx
12/20/2003	1.2	3.0
12/21/2003	1.3	3.0
12/22/2003	1.1	3.0
12/23/2003	1.2	3.0
12/24/2003	Offline	Offline
12/25/2003	Offline	Offline
12/26/2003	Offline	Offline
12/27/2003	Offline	Offline
12/28/2003	Offline	Offline
12/29/2003	Offline	Offline
12/30/2003	Offline	Offline
12/31/2003	Offline	Offline

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2B
EXCLUDED DATA - QUARTER 4, 2003

Date	Hours Data Excluded	NOx Value of Excluded Data	CO Value of Excluded Data	Reason for Exclusion
12/21/2003	1100	19.8	832.9	Shutdown
12/22/2003	0300	*	8.4	Start-up
	0400	57.6	583.9	Start-up
	0500	69.8	302.6	Start-up
	0600	33	118.1	Start-up
12/23/2003	2200	37.6	765.1	Shutdown

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

* Data not excluded.

BAYSIDE POWER STATION - CT 2B
MAINTENANCE/REPAIR OF CEMS - QUARTER 4, 2003

Date	Unusual Maint. Or Repair of CEMS
	No Unusual Maintenance of CEMS

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2B
MONITOR DOWNTIME - QUARTER 2, 2003

Date	Hours of Missing Data for Monitor Downtime	Reason for Monitor Downtime

Monitor availability:	100%

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR75 - APPENDIX A
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2B
Test Date: 12/16/03

Run Number	Run Times Start	Stop	Unit Load	Air Services Group - Test Data RM - 7E NO_x ppmvd	RM - 3A O_2 %v, dry	RM - 19 NO_x lbs/mmBtu	Continuous Emissions Monitor RM - 19 NO_x lbs/mmBtu	Difference lbs/mmbtu	Run Flag
1	09:31	09:52	166	3.48	13.87	0.011	0.011	0.000	1
2	10:31	10:52	164	3.42	13.86	0.011	0.011	0.000	1
3	11:08	11:29	163	3.42	13.85	0.011	0.011	0.000	1
4	11:45	12:06	161	3.42	13.85	0.011	0.011	0.000	1
5	12:20	12:41	161	3.36	13.84	0.010	0.011	-0.001	1
6	12:53	13:14	160	3.30	13.84	0.010	0.011	-0.001	1
7	13:29	13:50	161	3.32	13.80	0.010	0.011	-0.001	1
8	14:07	14:28	161	3.39	13.80	0.010	0.011	-0.001	1
9	14:42	15:03	160	3.42	13.81	0.010	0.011	-0.001	1
		Means:	162			0.010	0.011	-0.001	

Standard Deviation of Differences:	0.001
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.000
Relative Accuracy (RA), Calculated Against Mean Reference Method Value:	9.20
Relative Accuracy (RA), Calculated As Mean Difference, Alternative Performance Specification (APS):	0.001
Bias Test:	PASSED
Bias Adjustment Factor (BAF):	1.000

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR75 - APPENDIX A
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2B
Test Date: 12/16/03

Run Number	Run Times Start	Stop	Unit Load	Air Services Group - Test Data RM - 3A CO_2, % volume dry	Continuous Emissions Monitor CO_2, % volume dry	Difference CO_2, % volume dry	Run Flag
1	09:31	09:52	166	4.080	3.814	0.266	1
2	10:31	10:52	164	4.080	3.832	0.248	1
3	11:08	11:29	163	4.090	3.848	0.242	1
4	11:45	12:06	161	4.080	3.851	0.229	1
5	12:20	12:41	161	4.100	3.839	0.261	1
6	12:53	13:14	160	4.080	3.818	0.262	1
7	13:29	13:50	161	4.070	3.820	0.250	1
8	14:07	14:28	161	4.040	3.820	0.220	1
9	14:42	15:03	160	4.040	3.820	0.220	1
		Means:	162	4.073	3.829	0.244	

Standard Deviation of Differences:	0.018
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.014
Relative Accuracy (RA):	6.33

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

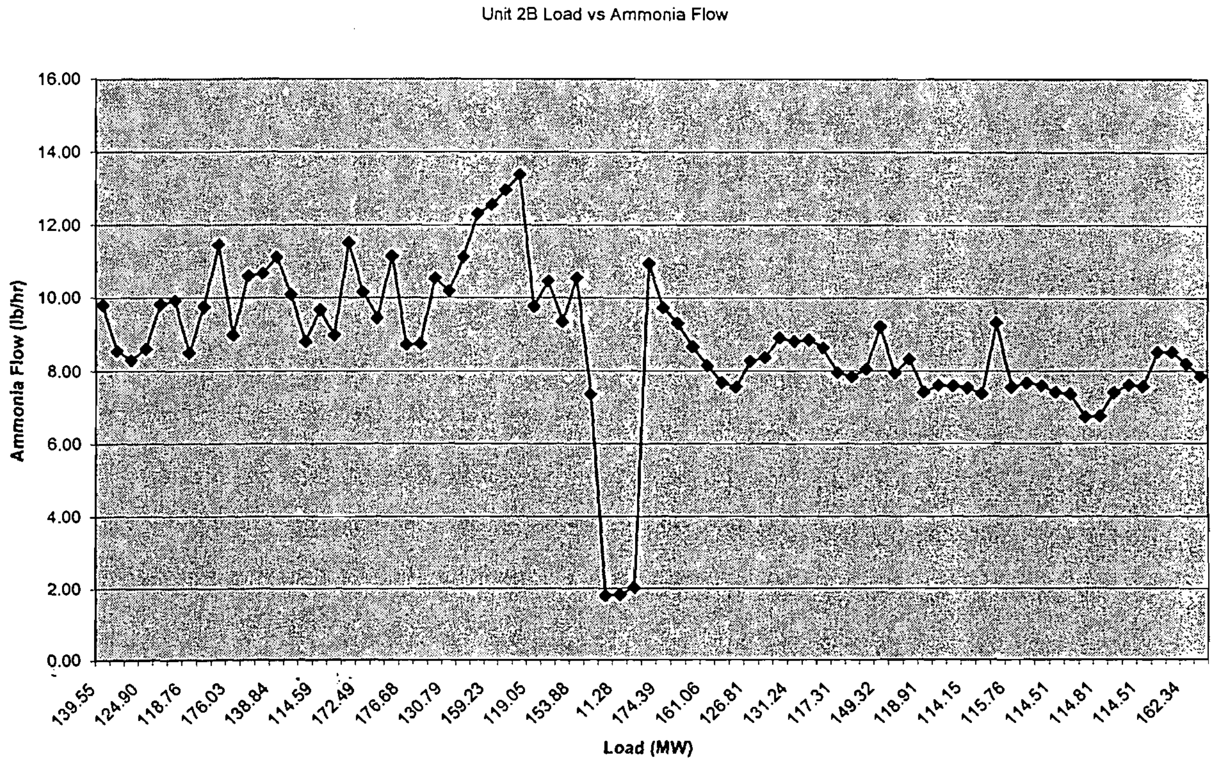
40CFR60 - APPENDIX B, PERFORMANCE SPECIFICATION 4
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2B
Test Date: 12/16/03

Applicable Standard: 7.8 ppmvd CO @ 15% O_2

				Air Services Group - Test Data			Continuous Emissions Monitor		Difference	
Run Number	Run Times Start	Stop	Unit Load	RM -10 CO ppmvd	RM - 3A O_2 %v, dry	CO ppmvd @ 15% O_2	CO ppmvd	CO ppmvd @ 15% O_2	CO ppmvd @ 15% O_2	Run Flag
1	09:31	09:52	166	1.05	13.87	0.881	1.32	1.165	-0.284	1
2	10:31	10:52	164	1.14	13.86	0.955	1.41	1.214	-0.259	1
3	11:08	11:29	163	0.93	13.85	0.778	1.18	1.055	-0.277	1
4	11:45	12:06	161	1.11	13.85	0.929	1.36	1.159	-0.230	1
5	12:20	12:41	161	1.27	13.84	1.061	1.54	1.332	-0.271	1
6	12:53	13:14	160	1.18	13.84	0.986	1.51	1.300	-0.314	1
7	13:29	13:50	161	1.12	13.80	0.931	1.48	1.283	-0.352	1
8	14:07	14:28	161	1.03	13.80	0.856	1.40	1.209	-0.353	1
9	14:42	15:03	160	0.90	13.81	0.749	1.30	1.100	-0.351	1
		Means:	162			0.903		1.202	-0.299	

Standard Deviation of Differences:	0.045
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.035
Relative Accuracy (RA), Calculated Against Mean Reference Method Value:	36.98 %
Relative Accuracy (RA), Calculated Against Applicable Standard:	4.28 %



Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 24

SUMMARY REPORT – NO_x EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE NSPS SUBPART GG

Pollutant: NOx - Combustion Turbine

Emission Limitation: 3.5 ppmvd @ 15% O_2 on a 24-hour block average

Reporting period dates: From 10/01/03 to 12/31/03

Company: Tampa Electric Company
Address: P.O. Box 111
Tampa, FL 33601-0111

Process Unit Description : 169 MW Combined Cycle Combustion Turbine (CT 2C)

Monitor Manufacturer and Model No.: Thermal Environmental 42CLS

Date of Latest CMS Certification or Audit: December 2003

Total source operating time in reporting period[1]: 82

Emission Data Summary[1]		CMS Performance Summary[2]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown	8	a. Monitor equipment malfunctions	4
b. Control equipment problems	0	b. Non-Monitor equipment malfunctions	0
c. Process problems	0	c. Quality assurance calibration	0
d. Other known causes	0	d. Other known causes	0
e. Unknown causes	0	e. Unknown causes	0
2. Total duration of excess emission	8	2. Total CMS Downtime	4
3. Total duration of excess emissions x (100) / Total source operating time	10 %	3. Total CMS Downtime x (100) / Total source operating time	5 %

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.

This form is used for reporting excess emission according to New Source Performance Standard (NSPS) Subpart GG only. (CO is not a regulated by Subpart GG and is reported under the semi-annual excess emission report required by Section III, permit condition 25.)

1. For gases record all times in hours.

2. 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 60.7(c) shall be submitted.

   TEC Note: The summary report form and the excess emission report required will also be submitted in the semi-annual report.

Per Title V Permit #0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2C
24 - HOUR BLOCK AVERAGE - QUARTER 4, 2003

Date	24-hour block CO	24-hour block NOx
12/20/2003	0.9	3.0
12/21/2003	1.0	3.0
12/22/2003	0.9	3.0
12/23/2003	1.0	3.0
12/24/2003	Offline	Offline
12/25/2003	Offline	Offline
12/26/2003	Offline	Offline
12/27/2003	Offline	Offline
12/28/2003	Offline	Offline
12/29/2003	Offline	Offline
12/30/2003	Offline	Offline
12/31/2003	Offline	Offline

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2C
EXCLUDED DATA - QUARTER 4, 2003

Date	Hours Data Excluded	NOx Value of Excluded Data	CO Value of Excluded Data	Reason for Exclusion
12/21/2003	1200	18.3	259.2	Shutdown
	0200	44.2	302.7	Cold Steam Turbine Start-up
	0300	66.9	172.2	Cold Steam Turbine Start-up
	0400	60.3	*	Cold Steam Turbine Start-up
	0700	54.3	*	Cold Steam Turbine Start-up
	0800	55	*	Cold Steam Turbine Start-up
	0900	18.1	*	Cold Steam Turbine Start-up
12/23/2003	2400	14.4	252.9	Shutdown

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2C
MAINTENANCE/REPAIR OF CEMS - QUARTER 4, 2003

Date	Unusual Maint. Or Repair of CEMS
	No Unusual Maintenance of CEMS

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2C
MONITOR DOWNTIME - QUARTER 4, 2003

Date	Hours of Missing Data for Monitor Downtime	Reason for Monitor Downtime
12/22/2003	4	CO Monitor Problems

Monitor availability:	95%

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR75 - APPENDIX A
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2C
Test Date: 12/20/03

				Air Services Group - Test Data			Continuous Emissions Monitor		
Run	Run Times		Unit	RM - 7E NO_x	RM - 3A O_2	RM - 19 NO_x	RM - 19 NO_x	Difference	Run
Number	Start	Stop	Load	ppmvd	%v, dry	lbs/mmBtu	lbs/mmBtu	lbs/mmbtu	Flag
1	10:51	11:12	176	3.69	14.01	0.012	0.011	0.001	1
2	11:30	11:51	176	3.70	14.03	0.012	0.011	0.001	1
3	12:05	12:26	175	3.66	14.02	0.012	0.011	0.001	1
4	12:44	13:05	175	3.64	14.00	0.011	0.011	0.000	1
5	13:24	13:45	174	3.65	13.94	0.011	0.011	0.000	1
6	13:55	14:16	174	3.63	13.89	0.011	0.011	0.000	1
7	14:26	14:47	174	3.63	13.92	0.011	0.011	0.000	1
8	14:57	15:18	174	3.64	13.96	0.011	0.011	0.000	1
9	15:28	15:49	174	3.63	13.96	0.011	0.011	0.000	1
		Means:	175			0.011	0.011	0.000	

Standard Deviation of Differences:	0.001
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.000
Relative Accuracy (RA), Calculated Against Mean Reference Method Value:	6.33
Relative Accuracy (RA), Calculated As Mean Difference, Alternative Performance Specification (APS):	0.000
Bias Test:	PASSED
Bias Adjustment Factor (BAF):	1.000
Alternative Bias Adjustment Factor (BAF):	N/A

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR75 - APPENDIX A
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2C
Test Date: 12/20/03

Run Number	Run Times Start	Stop	Unit Load	Air Services Group - Test Data RM - 3A CO_2, % volume dry	Continuous Emissions Monitor CO_2, % volume dry	Difference CO_2, % volume dry	Run Flag
1	10:51	11:12	176	4.090	3.999	0.091	1
2	11:30	11:51	176	4.080	4.000	0.080	1
3	12:05	12:26	175	4.080	4.010	0.070	1
4	12:44	13:05	175	4.080	4.007	0.073	1
5	13:24	13:45	174	4.090	4.010	0.080	1
6	13:55	14:16	174	4.090	4.019	0.071	1
7	14:26	14:47	174	4.090	4.020	0.070	1
8	14:57	15:18	174	4.090	4.022	0.068	1
9	15:28	15:49	174	4.090	4.020	0.070	1
		Means:	175	4.087	4.012	0.075	

Standard Deviation of Differences:	0.007
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.006
Relative Accuracy (RA):	1.97

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

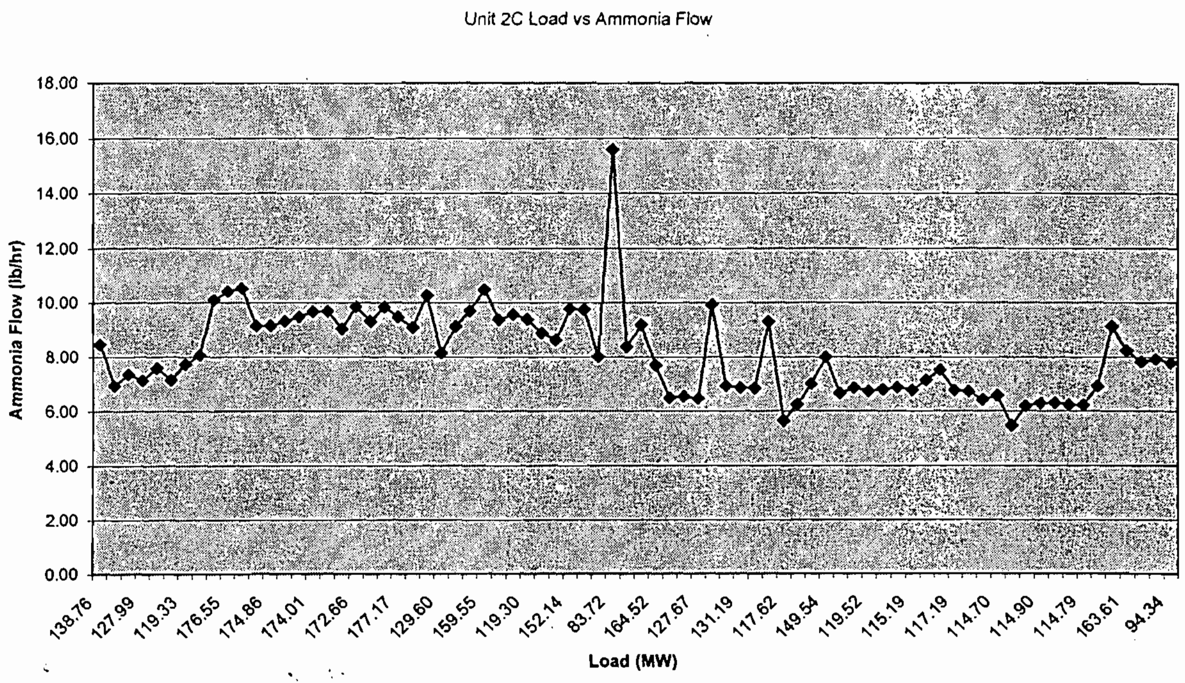
40CFR60 - APPENDIX B, PERFORMANCE SPECIFICATION 4
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2C
Test Date: 12/20/03

Applicable Standard: 7.8 ppmvd CO @ 15% O_2

				Air Services Group - Test Data			Continuous Emissions Monitor		Difference	
Run Number	Run Times Start	Run Times Stop	Unit Load	RM -10 CO ppmvd	RM - 3A O_2 %v, dry	CO ppmvd @ 15% O_2	CO ppmvd	CO ppmvd @ 15% O_2	CO ppmvd @ 15% O_2	Run Flag
1	10:51	11:12	176	0.94	14.01	0.805	0.90	0.800	0.005	1
2	11:30	11:51	176	0.96	14.03	0.824	0.90	0.800	0.024	1
3	12:05	12:26	175	0.87	14.02	0.746	0.90	0.800	-0.054	1
4	12:44	13:05	175	0.77	14.00	0.658	0.90	0.800	-0.142	1
5	13:24	13:45	174	0.69	13.94	0.585	0.89	0.791	-0.206	1
6	13:55	14:16	174	0.70	13.89	0.589	0.89	0.791	-0.202	1
7	14:26	14:47	174	0.70	13.92	0.592	0.89	0.786	-0.194	1
8	14:57	15:18	174	0.73	13.96	0.621	0.85	0.755	-0.134	1
9	15:28	15:49	174	0.77	13.96	0.655	0.81	0.712	-0.057	1
		Means:	175			0.675		0.782	-0.107	

Standard Deviation of Differences:	0.089	
Number of Valid Runs Included in Data Set:	9	
t-value for Data Set:	2.306	
2.5% Error Confidence Coefficient (CC) for Data Set:	0.068	
Relative Accuracy (RA), Calculated Against Mean Reference Method Value:	25.94	%
Relative Accuracy (RA), Calculated Against Applicable Standard:	2.24	%



Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 24

SUMMARY REPORT – NO_x EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE NSPS SUBPART GG

Pollutant: NOx - Combustion Turbine

Emission Limitation: 3.5 ppmvd @ 15% O_2 on a 24-hour block average

Reporting period dates: From 10/01/03 to 12/31/03

Company: Tampa Electric Company
Address: P.O. Box 111
Tampa, FL 33601-0111

Monitor Manufacturer and Model No.: Thermal Environmental 42CLS

Date of Latest CMS Certification or Audit: December 2003

Process Unit Description: 169 MW Combined Cycle Combustion Turbine (CT 2D)

Total source operating time in reporting period[1]: 78

Emission Data Summary[1]		CMS Performance Summary[2]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/Shutdown	4	a. Monitor equipment malfunctions	0
b. Control equipment problems	0	b. Non-Monitor equipment malfunctions	0
c. Process problems	0	c. Quality assurance calibration	0
d. Other known causes	0	d. Other known causes	0
e. Unknown causes	0	e. Unknown causes	0
2. Total duration of excess emission	4	2. Total CMS Downtime	0
3. Total duration of excess emissions x (100) / Total source operating time	5 %	3. Total CMS Downtime x (100) / Total source operating time	0%

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.

This form is used for reporting excess emission according to New Source Performance Standard (NSPS) Subpart GG only. (CO is not a regulated by Subpart GG and is reported under the semi-annual excess emission report required by Section III, permit condition 25.)

1. For gases record all times in hours.

2. 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 60.7(c) shall be submitted.

   TEC Note: The summary report form and the excess emission report required will also be submitted in the semi-annual report.

Per Title V Permit #0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2D
24 - HOUR BLOCK AVERAGE - QUARTER 4, 2003

Date	24-hour block CO	24-hour block NOx
12/20/2003	0.8	3.0
12/21/2003	1.0	3.0
12/22/2003	0.8	3.0
12/23/2003	0.9	3.0
12/24/2003	Offline	Offline
12/25/2003	Offline	Offline
12/26/2003	Offline	Offline
12/27/2003	Offline	Offline
12/28/2003	Offline	Offline
12/29/2003	Offline	Offline
12/30/2003	Offline	Offline
12/31/2003	Offline	Offline

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2D
EXCLUDED DATA - QUARTER 4, 2003

Date	Hours Data Excluded	NOx Value of Excluded Data	CO Value of Excluded Data	Reason for Exclusion
12/21/2003	1200	55.2	594.8	Shutdown
12/22/2003	0800	50.9	458	Start-up
	0900	38.3	341.3	Start-up
12/24/2003	2400	5.7	41.5	Shutdown

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

* Data not excluded.

BAYSIDE POWER STATION - CT 2D
MAINTENANCE/REPAIR OF CEMS - QUARTER 4, 2003

Date	Unusual Maint. Or Repair of CEMS
	No Unusual Maintenance of CEMS

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

BAYSIDE POWER STATION - CT 2D
MONITOR DOWNTIME - QUARTER 4, 2003

Date	Hours of Missing Data for Monitor Downtime	Reason for Monitor Downtime

Monitor availability:	100%

Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 25

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR75 - APPENDIX A
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2D
Test Date: 12/17/03

				Air Services Group - Test Data			Continuous Emissions Monitor		
Run	Run Times		Unit	RM - 7E NO_x	RM - 3A O_2	RM - 19 NO_x	RM - 19 NO_x	Difference	Run
Number	Start	Stop	Load	ppmvd	%v, dry	lbs/mmBtu	lbs/mmBtu	lbs/mmbtu	Flag
1	09:32	09:53	172	3.74	13.84	0.012	0.011	0.001	1
2	10:46	11:07	173	3.81	13.83	0.012	0.011	0.001	1
3	11:23	11:44	173	3.73	13.85	0.011	0.011	0.000	1
4	11:55	12:16	172	3.76	13.85	0.012	0.011	0.001	1
5	12:31	12:52	172	3.76	13.84	0.012	0.011	0.001	1
6	13:05	13:26	173	3.81	13.87	0.012	0.011	0.001	1
7	13:42	14:03	173	3.87	13.89	0.012	0.011	0.001	1
8	14:15	14:36	173	3.90	13.89	0.012	0.011	0.001	1
9	14:48	15:09	173	3.95	13.88	0.012	0.011	0.001	1
		Means:	173			0.012	0.011	0.001	

Standard Deviation of Differences:	0.000
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.000
Relative Accuracy (RA), Calculated Against Mean Reference Method Value:	9.63
Relative Accuracy (RA), Calculated As Mean Difference, Alternative Performance Specification (APS):	0.001
Bias Test:	FAILED
Bias Adjustment Factor (BAF):	1.081
Alternative Bias Adjustment Factor (BAF):	N/A

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40CFR75 - APPENDIX A
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2D
Test Date: 12/17/03

Run Number	Run Times Start	Stop	Unit Load	Air Services Group - Test Data RM - 3A CO_2, % volume dry	Continuous Emissions Monitor CO_2, % volume dry	Difference CO_2, % volume dry	Run Flag
1	09:32	09:53	172	4.150	4.084	0.066	1
2	10:46	11:07	173	4.140	4.080	0.060	1
3	11:23	11:44	173	4.110	4.071	0.039	1
4	11:55	12:16	172	4.090	4.075	0.015	1
5	12:31	12:52	172	4.090	4.071	0.019	1
6	13:05	13:26	173	4.090	4.089	0.001	1
7	13:42	14:03	173	4.100	4.119	-0.019	1
8	14:15	14:36	173	4.100	4.140	-0.040	1
9	14:48	15:09	173	4.100	4.146	-0.046	1
		Means:	173	4.108	4.097	0.011	

Standard Deviation of Differences:	0.041
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.031
Relative Accuracy (RA):	1.02

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

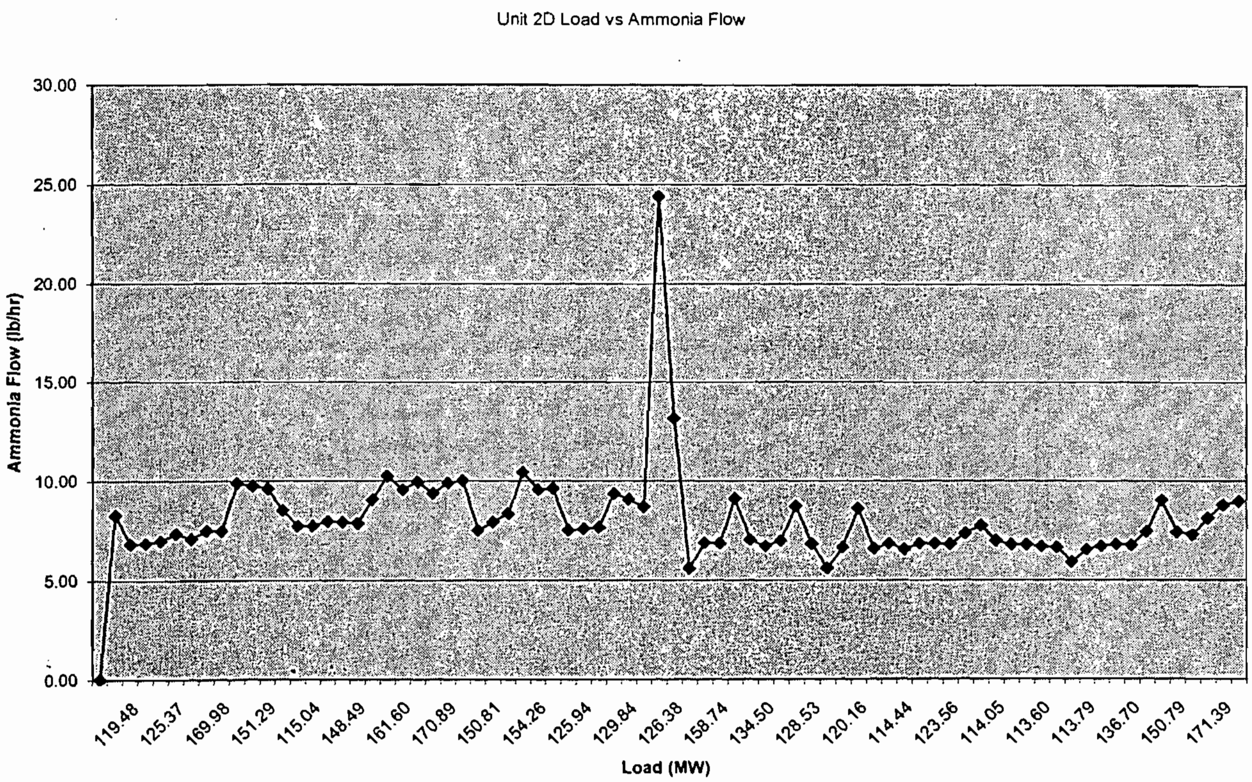
40CFR60 - APPENDIX B, PERFORMANCE SPECIFICATION 4
RELATIVE ACCURACY TEST AUDIT

Customer: Tampa Electric Company
Facility: Bayside Power Station
Source: CT-2D
Test Date: 12/17/03

Applicable Standard: 7.8 ppmvd CO @ 15% O_2

Run Number	Run Times Start	Run Times Stop	Unit Load	Air Services Group - Test Data: RM -10 CO ppmvd	RM - 3A O_2 %v, dry	CO ppmvd @ 15% O_2	Continuous Emissions Monitor: CO ppmvd	CO ppmvd @ 15% O_2	Difference: CO ppmvd @ 15% O_2	Run Flag
1	09:32	09:53	172	0.87	13.84	0.727	0.95	0.781	-0.054	1
2	10:46	11:07	173	0.82	13.83	0.684	0.96	0.773	-0.089	1
3	11:23	11:44	173	0.87	13.85	0.728	0.96	0.777	-0.049	1
4	11:55	12:16	172	0.83	13.85	0.695	0.98	0.786	-0.091	1
5	12:31	12:52	172	0.96	13.84	0.802	0.96	0.764	0.038	1
6	13:05	13:26	173	0.99	13.87	0.831	0.90	0.709	0.122	1
7	13:42	14:03	173	0.93	13.89	0.783	0.85	0.700	0.083	1
8	14:15	14:36	173	0.93	13.89	0.783	0.80	0.686	0.097	1
9	14:48	15:09	173	0.96	13.88	0.807	0.80	0.627	0.180	1
		Means:	173			0.760		0.734	0.026	

Standard Deviation of Differences:	0.100
Number of Valid Runs Included in Data Set:	9
t-value for Data Set:	2.306
2.5% Error Confidence Coefficient (CC) for Data Set:	0.077
Relative Accuracy (RA), Calculated Against Mean Reference Method Value:	13.60 %
Relative Accuracy (RA), Calculated Against Applicable Standard:	1.32 %



Per Air Permit No. 0570040-015-AC, Section III, Specific Condition 24

ATTACHMENT 5

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40 CFR 60
APPENDIX F
DATA ASSESSMENT REPORT

Period Ending Date: December 31, Year: 2003

Company Name: Tampa Electric Company

Plant Name: Bayside Power Station Source ORIS Code 7873

Source Common Name: Unit 1 EU No.: 020, 021, 022

CEMS Information

	CT-1A	CT-1B	CT-1C
CO Manufacturer:	Thermo Environmental		
CO Model Number:	48C		
CO Serial Number:	48C-73684-374	48C-73423-373	48C-73685-374
CO Span Value:	Dual Range 0-20/0-1000 ppmv		
CO_2 Manufacturer:	Siemens		
CO_2 Model Number:	Ultramat - 6		
CO_2 Serial Number	N1-ND-0876	N1-ND-0870	N1-ND-0877
CO_2 Span Value:	0 - 10% volume		

Note: Cylinder Gas Audit Relative Accuracy (RA) calculated as:

$$A = ((Cm - Ca) / Ca) \times 100$$

Where:

Cm = Average of CEMS response during audit in units of applicable standard or apprpriate concentration.

Ca = Average audit value (CGA certified value or three-run average for RAA) in units of applicable standard or appropriate concentration.

Appendix F, Equation 1-1

Additionally, low range analyzers that fail to meet the $\pm$ 15% are subject to a $\pm$ 5 ppm "criteria for excessive audit inaccuracy" as specified in Appendix F, 5.2.3 and calculated as:

$$Cm - Ca$$

1. Accuracy Assessment Results - Quarter 4, 2003

B. Cylinder Gas Audit for CO in ppm.

CT-1A

Low-range

	Audit Point #1		Audit Point #2
Audit Date:	10/18/2003		10/18/2003
Cylinder ID Number:	ALM - 066579		AAL - 955
Certification Date:	07/28/2003		09/14/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	5.17	ppm	11.10
CEMs Response:	5.300	ppm	11.367
RA (± 15%):	2.51	%	2.41
RA (± 5 ppm):	N/A	ppm	N/A

High-range

	Audit Point #1		Audit Point #2
Audit Date:	10/18/2003		10/18/2003
Cylinder ID Number:	ALM - 050741		ALM - 032306
Certification Date:	01/31/2003		09/09/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	244.0	ppm	545.0
CEMs Response:	249.600	ppm	544.667
Accuracy:	2.30	%	-0.06

1. Accuracy Assessment Results - Quarter 4, 2003

B. Cylinder Gas Audit for CO in ppm.

CT-1B

Low-range

	Audit Point #1		Audit Point #2
Audit Date:	10/27/2003		10/27/2003
Cylinder ID Number:	ALM - 066579		AAL - 19084
Certification Date:	07/28/2003		08/03/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	5.17	ppm	11.40
CEMs Response:	6.067	ppm	11.900
RA (± 15%):	17.35	%	4.39
RA (± 5 ppm):	0.90	ppm	N/A

High-range

	Audit Point #1		Audit Point #2
Audit Date:	10/27/2003		10/27/2003
Cylinder ID Number:	AAL - 18340		ALM - 046642
Certification Date:	02/20/2003		07/21/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	254.0	ppm	554.0
CEMs Response:	261.400	ppm	526.800
Accuracy:	2.91	%	-4.91

1. Accuracy Assessment Results - Quarter 4, 2003

B. Cylinder Gas Audit for CO in ppm.

CT-1C

Low-range

	Audit Point #1		Audit Point #2
Audit Date:	10/27/2003		10/27/2003
Cylinder ID Number:	ALM - 066579		AAL - 19084
Certification Date:	07/28/2003		08/03/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	5.17	ppm	11.40
CEMs Response:	5.667	ppm	11.267
RA (± 15%):	9.61	%	-1.17
RA (± 5 ppm):	N/A	ppm	N/A

High-range

	Audit Point #1		Audit Point #2
Audit Date:	10/27/2003		10/27/2003
Cylinder ID Number:	AAL - 18340		ALM - 046642
Certification Date:	02/20/2003		07/21/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	254.0	ppm	554.0
CEMs Response:	274.667	ppm	566.500
Accuracy:	8.14	%	2.26

1. Accuracy Assessment Results - Quarter 4, 2003

B. Cylinder Gas Audit for CO_2 in %v/v.

CT-1A

	Audit Point #1		Audit Point #2
Audit Date:	10/18/2003		10/18/2003
Cylinder ID Number:	ALM - 045675		ALM - 046413
Certification Date:	02/04/2003		08/29/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	2.06	%, v/v	5.51
CEMs Response:	2.067	%, v/v	5.500
Accuracy:	0.34	%	-0.18

1. Accuracy Assessment Results - Quarter 4, 2003

B. Cylinder Gas Audit for CO_2 in %v/v.

CT-1B

	Audit Point #1		Audit Point #2
Audit Date:	10/27/2003		10/27/2003
Cylinder ID Number:	ALM - 045052		ALM - 039271
Certification Date:	02/20/2003		08/27/2002
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	2.53	%, v/v	5.46
CEMs Response:	2.600	%, v/v	5.433
Accuracy:	2.77	%	-0.49

1. Accuracy Assessment Results - Quarter 4, 2003

B. Cylinder Gas Audit for CO_2 in %v/v.

CT-1C

	Audit Point #1		Audit Point #2
Audit Date:	10/27/2003		10/27/2003
Cylinder ID Number:	ALM - 045052		ALM - 039271
Certification Date:	02/20/2003		08/27/2002
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	2.53	%, v/v	5.46
CEMs Response:	2.500	%, v/v	5.300
Accuracy:	-1.19	%	-2.93

2. Calibration Drift Assessment.

A. Out-of-control periods.

1. Date(s): ____________
____
____
____
____
____

2. Number of days: ____________
____
____
____
____

B. Corrective Action Taken.

TECO
TAMPA ELECTRIC

Environmental Services
Air Services Group

40 CFR 60
APPENDIX F
DATA ASSESSMENT REPORT

Period Ending Date:	December 31,	Year:	2003
Company Name:	Tampa Electric Company		
Plant Name:	Bayside Power Station	Source ORIS Code	7873
Source Common Name:	Unit 2	EU No.: 023, 024, 025, 026	

CEMS Information

	CT-2A	CT-2B	CT-2C	CT-2D
CO Manufacturer:	Thermo Environmental			
CO Model Number:	48C			
CO Serial Number:	48C-74345-376	48C-74342-376	48C-74343-376	48C-73683-374
CO Span Value:	Dual Range 0-20/0-1000 ppmv			
CO_2 Manufacturer:	Siemens			
CO_2 Model Number:	Ultramat - 6			
CO_2 Serial Number	N1-ND-0892	N1-ND-0897	N1-ND-0984	N1-ND-0893
CO_2 Span Value:	0 - 10% volume			

1. Accuracy Assessment Results

A. Relative Accuracy Test Audit(s) for CO in ppm.

	CT - 2A	
Audit Date:	11/14/2003	
Reference Method(s) Employed:	10/3a	
Average Reference Method Value:	0.779	ppmvd @ 15% O_2
Average CEM Value:	0.592	ppmvd @ 15% O_2
Absolute Value of Mean Difference:	0.187	ppmvd @ 15% O_2
Confidence Coefficient:	0.030	ppmvd @ 15% O_2

Percent Relative Accuracy (mean of reference methods):	27.9	%
Percent Relative Accuracy (applicable standard):	2.78	%

The applicable standard for this unit is 7.8 ppmvd @ 15% O_2.

1. Accuracy Assessment Results

A. Relative Accuracy Test Audit(s) for CO in ppm.

	CT - 2B	
Audit Date:	11/12/2003	
Reference Method(s) Employed:	10/3a	
Average Reference Method Value:	0.717	ppmvd @ 15% O_2
Average CEM Value:	0.630	ppmvd @ 15% O_2
Absolute Value of Mean Difference:	0.087	ppmvd @ 15% O_2
Confidence Coefficient:	0.013	ppmvd @ 15% O_2

Percent Relative Accuracy (mean of reference methods):	14.07	%
Percent Relative Accuracy (applicable standard):	1.29	%

The applicable standard for this unit is 7.8 ppmvd @ 15% O_2.

1. Accuracy Assessment Results

A. Relative Accuracy Test Audit(s) for CO in ppm.

	CT - 2C	
Audit Date:	12/20/2003	
Reference Method(s) Employed:	10/3a	
Average Reference Method Value:	0.675	ppmvd @ 15% O_2
Average CEM Value:	0.782	ppmvd @ 15% O_2
Absolute Value of Mean Difference:	0.107	ppmvd @ 15% O_2
Confidence Coefficient:	0.068	ppmvd @ 15% O_2

Percent Relative Accuracy (mean of reference methods):	25.9	%
Percent Relative Accuracy (applicable standard):	2.24	%

The applicable standard for this unit is 7.8 ppmvd @ 15% O_2.

1. Accuracy Assessment Results

A. Relative Accuracy Test Audit(s) for CO in ppm.

	CT - 2D	
Audit Date:	12/17/2003	
Reference Method(s) Employed:	10/3a	
Average Reference Method Value:	0.760	ppmvd @ 15% O_2
Average CEM Value:	0.734	ppmvd @ 15% O_2
Absolute Value of Mean Difference:	0.026	ppmvd @ 15% O_2
Confidence Coefficient:	0.077	ppmvd @ 15% O_2

Percent Relative Accuracy (mean of reference methods):	13.6	%
Percent Relative Accuracy (applicable standard):	1.32	%

The applicable standard for this unit is 7.8 ppmvd @ 15% O_2.

1. Accuracy Assessment Results

A. Relative Accuracy Test Audit(s) for CO_2 in % volume.

	CT - 2A	
Audit Date:	11/14/2003	
Reference Method(s) Employed:	3A	
Average Reference Method Value:	4.008	% volume
Average CEM Value:	4.014	% volume
Absolute Value of Mean Difference:	0.006	% volume
Confidence Coefficient:	0.006	% volume

Percent Relative Accuracy (mean of reference methods):	0.30 %
Percent Relative Accuracy (absolute difference):	0.01 % volume

1. Accuracy Assessment Results

A. Relative Accuracy Test Audit(s) for CO_2 in % volume.

	CT - 2B	
Audit Date:	11/12/2003	
Reference Method(s) Employed:	3A	
Average Reference Method Value:	4.060	% volume
Average CEM Value:	3.969	% volume
Absolute Value of Mean Difference:	0.090	% volume
Confidence Coefficient:	0.025	% volume

Percent Relative Accuracy (mean of reference methods):	2.83 %
Percent Relative Accuracy (absolute difference):	0.09 % volume

1. Accuracy Assessment Results

A. Relative Accuracy Test Audit(s) for CO_2 in % volume.

	CT - 2C	
Audit Date:	12/20/2003	
Reference Method(s) Employed:	3A	
Average Reference Method Value:	4.087	% volume
Average CEM Value:	4.012	% volume
Absolute Value of Mean Difference:	0.075	% volume
Confidence Coefficient:	0.006	% volume

Percent Relative Accuracy (mean of reference methods): 1.98 %

Percent Relative Accuracy (absolute difference): 0.08 % volume

1. Accuracy Assessment Results

A. Relative Accuracy Test Audit(s) for CO_2 in % volume.

	CT - 2D	
Audit Date:	12/17/2003	
Reference Method(s) Employed:	3A	
Average Reference Method Value:	4.108	% volume
Average CEM Value:	4.097	% volume
Absolute Value of Mean Difference:	0.011	% volume
Confidence Coefficient:	0.031	% volume

Percent Relative Accuracy (mean of reference methods):	1.02 %
Percent Relative Accuracy (absolute difference):	0.01 % volume

1. Accuracy Assessment Results *Quarter 4, 2003*

B. Cylinder Gas Audit for CO in ppm.

CT-2A

Low-range

	Audit Point #1		Audit Point #2
Audit Date:	10/07/2003		10/07/2003
Cylinder ID Number:	ALM - 066579		AAL - 18045
Certification Date:	07/28/2003		09/01/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	5.17	ppm	11.00
CEMs Response:	5.100	ppm	11.000
Accuracy:	-1.35	%	0.00

High-range

	Audit Point #1		Audit Point #2
Audit Date:	10/07/2003		10/07/2003
Cylinder ID Number:	ALM - 034825		ALM - 064853
Certification Date:	09/01/2003		08/31/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	249.0	ppm	542.0
CEMs Response:	247.300	ppm	540.767
Accuracy:	-0.68	%	-0.23

1. Accuracy Assessment Results *Quarter 4, 2003*

B. Cylinder Gas Audit for CO in ppm.

CT-2B

Low-range

	Audit Point #1		Audit Point #2
Audit Date:	09/05/2003		09/05/2003
Cylinder ID Number:	ALM -045402		AAL - 18045
Certification Date:	03/02/2002		AAL - 18045
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	5.08	ppm	11.00
CEMs Response:	5.067	ppm	10.967
Accuracy:	-0.26	%	-0.30

High-range

	Audit Point #1		Audit Point #2
Audit Date:	09/05/2003		09/05/2003
Cylinder ID Number:	ALM - 034825		ALM - 064853
Certification Date:	09/01/2003		08/31/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	249.0	ppm	542.0
CEMs Response:	250.733	ppm	539.867
Accuracy:	0.70	%	-0.39

1. Accuracy Assessment Results ***Quarter 4, 2003***

B. Cylinder Gas Audit for CO in ppm.

CT-2C

Low-range

	Audit Point #1		Audit Point #2
Audit Date:	11/18/2003		11/18/2003
Cylinder ID Number:	ALM - 005846		IL - 1617
Certification Date:	02/18/2002		02/02/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	6.07	ppm	11.30
CEMs Response:	6.000	ppm	11.367
Accuracy:	-1.15	%	0.59

High-range

	Audit Point #1		Audit Point #2
Audit Date:	11/18/2003		11/18/2003
Cylinder ID Number:	ALM - 034825		ALM - 054618
Certification Date:	09/01/2003		10/13/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	249.0	ppm	553.0
CEMs Response:	246.967	ppm	548.733
Accuracy:	-0.82	%	-0.77

1. Accuracy Assessment Results ***Quarter 4, 2003***

B. Cylinder Gas Audit for CO in ppm.

CT-2D

Low-range

	Audit Point #1		Audit Point #2
Audit Date:	11/14/2003		11/14/2003
Cylinder ID Number:	ALM - 005846		IL - 1617
Certification Date:	02/18/2002		02/02/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	6.07	ppm	11.30
CEMs Response:	6.000	ppm	11.200
Accuracy:	-1.15	%	-0.88

High-range

	Audit Point #1		Audit Point #2
Audit Date:	11/14/2003		11/14/2003
Cylinder ID Number:	ALM - 034825		ALM - 054618
Certification Date:	09/01/2003		10/13/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	249.0	ppm	553.0
CEMs Response:	248.200	ppm	550.300
Accuracy:	-0.32	%	-0.49

1. Accuracy Assessment Results Quarter 4, 2003

B. Cylinder Gas Audit for CO_2 in %v/v.

CT-2A

	Audit Point #1		Audit Point #2
Audit Date:	10/09/2003		10/09/2003
Cylinder ID Number:	ALM - 019353		ALM - 060212
Certification Date:	09/01/2003		08/29/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	2.5	%, v/v	5.50
CEMs Response:	2.533	%, v/v	5.500
Accuracy:	1.32	%	0.00

1. Accuracy Assessment Results Quarter 4, 2003

B. Cylinder Gas Audit for CO_2 in %v/v.

CT-2B

	Audit Point #1		Audit Point #2
Audit Date:	09/05/2003		09/05/2003
Cylinder ID Number:	ALM - 019353		ALM - 060212
Certification Date:	09/01/2003		08/29/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	2.5	%, v/v	5.5
CEMs Response:	2.500	%, v/v	5.500
Accuracy:	0.00	%	0.00

1. Accuracy Assessment Results Quarter 4, 2003

B. Cylinder Gas Audit for CO_2 in %v/v.

CT-2C

	Audit Point #1		Audit Point #2
Audit Date:	11/18/2003		11/18/2003
Cylinder ID Number:	ALM - 019353		ALM - 035365
Certification Date:	09/01/2003		09/02/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	2.5	%, v/v	5.5
CEMs Response:	2.533	%, v/v	5.500
Accuracy:	1.32	%	0.00

1. Accuracy Assessment Results Quarter 4, 2003

B. Cylinder Gas Audit for CO_2 in %v/v.

CT-2D

	Audit Point #1		Audit Point #2
Audit Date:	11/16/2003		11/16/2003
Cylinder ID Number:	ALM - 019353		ALM - 035365
Certification Date:	09/01/2003		09/02/2003
Certification Type:	USEPA Protocol 1, Procedure G1		
Certified Value:	2.5	%, v/v	5.5
CEMs Response:	2.533	%, v/v	5.500
Accuracy:	1.32	%	0.00

2. Calibration Drift Assessment.

A. Out-of-control periods.

1. Date(s): ________________
____
____
____
____
____

2. Number of days: ________________
____
____
____
____

B. Corrective Action Taken.

TECO
TAMPA ELECTRIC

RECEIVED
MAR 21 2003
BUREAU OF AIR REGULATION

March 17, 2003

Mr. Lynn Haynes
Region IV
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7915 5450 0435

Ms. Trina Vielhauer
Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7902 3322 1443

Re: Tampa Electric Company
Bayside Power Station Unit 1
Commercial Operations Notification
Air Permit No. PSD-FL-301A
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Hayes and Ms. Vielhauer:

Tampa Electric Company (TEC) is notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the date of initial commercial operations. TEC hereby gives notice of commercial operation as defined in 40 CFR Part 72.2: Commence commercial operation means to have begun to generate electricity for sale, including the sale of test generation, for environmental purposes, of Bayside Power Station Unit 1. Bayside Power Station Unit 1 (BPS) consists of three General Electric PG7241FA, 169 megawatt Gas Turbines (GT) at the BPS facility. Each of these three GT's, Bayside 1A, 1B, and 1C, has a 150 foot stack and is connected to its own Heat Recovery Steam Generator. TEC is giving notification that the GTs commenced commercial operations, per 40 CFR 72.2 for environmental purposes, in the following order and dates:

BPS 1A - March 17, 2003
BPS 1B - March 15, 2003
BPS 1C - March 11, 2003

If you have any questions, please call me at (813) 641-5034.

Sincerely,

for

Laura R. Crouch
Manager- Air Programs
Environmental Affairs

EA/gm/DNL157

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC
Mr. S. Sheplak- FDEP

Sheplak, Scott

From: Drupatie Latchman [dlatchman@tecoenergy.com]

Sent: Sunday, March 16, 2003 4:45 PM

To: Linero, Alvaro; Proses, Bill; Pichard, Errin; Kissel, Gerald; Sheplak, Scott; Vielhauer, Trina; Oliva.Manuel@epamail.epa.gov; leed@epchc.org; woodard@epcjanus.epchc.org

Subject: Bayside Unit 1 Initial Certification Testing-Project No.0570040-15-AC, ORIS code #7873

Tampa Electric Company (TEC) is re-notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the initial Continuous Emissions Monitoring System (CEMS) certification test. The initial CEMS test being performed are the cycle response time test, linearity and drift test. TEC hereby gives notice that the initial CEMS certification test wasperformed for Bayside Power Station (BPS) Unit 1, that is the cycle response time test, linearity and drift test, on the following dates:

Testing Completed:
BPS 1A- Completed on March 15, 2003
BPS 1B- Completed on March 12, 2003
BPS 1C- Completed on March 11, 2003

The RATA and stratification will be performed with the initial compliance test required by 40 CFR 60 and Bayside PSD permit. For Bayside Power Station (BPS) Unit 1, that is the RATA and stratification may be performed, on the following dates and order:

BPS 1A- April 09, 2003
BPS 1B- April 08, 2003
BPS 1C- April 07, 2003

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034. Please let me know if you receive this message.

Sincerely,

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

Sheplak, Scott

From: Drupatie Latchman [dlatchman@tecoenergy.com]

Sent: Friday, March 14, 2003 6:35 PM

To: Linero, Alvaro; Proses, Bill; Pichard, Errin; Kissel, Gerald; Sheplak, Scott; Vielhauer, Trina; Oliva.Manuel@epamail.epa.gov; leed@epchc.org; woodard@epcjanus.epchc.org

Subject: Bayside Unit 1 Initial Certification Testing-Project No.0570040-15-AC, ORIS code #7873

Tampa Electric Company (TEC) is re-notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the initial Continuous Emissions Monitoring System (CEMS) certification test. The initial CEMS test being performed are the cycle response time test, linearity and drift test. TEC hereby gives notice that the initial CEMS certification test may be performed for Bayside Power Station (BPS) Unit 1, that is the cycle response time test, linearity and drift test, on the following dates:

To be Completed:
BPS 1A- March 15 or 16, 2003

Testing Completed:
BPS 1B- Completed on March 12, 2003
BPS 1C- Completed on March 11, 2003

The RATA and stratification will be performed with the initial compliance test required by 40 CFR 60 and Bayside PSD permit. For Bayside Power Station (BPS) Unit 1, that is the RATA and stratification may be performed, on the following dates and order:

BPS 1A- April 09, 2003
BPS 1B- April 08, 2003
BPS 1C- April 07, 2003

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034. Please let me know if you receive this message.

Sincerely,

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

Sheplak, Scott

From: Drupatie Latchman [dlatchman@tecoenergy.com]

Sent: Thursday, March 13, 2003 8:09 AM

To: Linero, Alvaro; Proses, Bill; Pichard, Errin; Kissel, Gerald; Sheplak, Scott; Vielhauer, Trina; haynes.wilson@epa.gov; Oliva.Manuel@epamail.epa.gov; leed@epchc.org; woodard@epcjanus.epchc.org

Subject: Bayside Unit 1 Initial Certification Testing-Project No.0570040-15-AC, ORIS code #7873

Tampa Electric Company (TEC) is re-notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the initial Continuous Emissions Monitoring System (CEMS) certification test. The initial CEMS test being performed are the cycle response time test, linearity and drift test. TEC hereby gives notice that the initial CEMS certification test may be performed for Bayside Power Station (BPS) Unit 1, that is the cycle response time test, linearity and drift test, on the following dates:

To be Completed:
BPS 1A- March 13 or 14, 2003

Testing Completed:
BPS 1B- Completed on March 12, 2003
BPS 1C- Completed on March 11, 2003

The RATA and stratification will be performed with the initial compliance test required by 40 CFR 60 and Bayside PSD permit. For Bayside Power Station (BPS) Unit 1, that is the RATA and stratification may be performed, on the following dates and order:

BPS 1A- April 09, 2003
BPS 1B- April 08, 2003
BPS 1C- April 07, 2003

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034. Please let me know if you receive this message.

Sincerely,

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

Sheplak, Scott

From: Drupatie Latchman [dlatchman@tecoenergy.com]

Sent: Tuesday, March 11, 2003 9:36 AM

To: Linero, Alvaro; Proses, Bill; Pichard, Errin; Kissel, Gerald; Sheplak, Scott; Vielhauer, Trina; haynes.wilson@epa.gov; nguyen.kim@epa.gov; leed@epchc.org; woodard@epcjanus.epchc.org

Subject: Bayside Unit 1 Initial Certification Testing-Project No.0570040-15-AC, ORIS code #7873

Tampa Electric Company (TEC) is re-notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the initial Continuous Emissions Monitoring System (CEMS) certification test. The initial CEMS test being performed are the cycle response time test, linearity and drift test. TEC hereby gives notice that the initial CEMS certification test may be performed for Bayside Power Station (BPS) Unit 1, that is the cycle response time test, linearity and drift test, on the following dates:

BPS 1A- March 11 or 12, 2003
BPS 1B- March 11or 12, 2003
BPS 1C- March 11or 12, 2003

The RATA and stratification will be performed with the initial compliance test required by 40 CFR 60 and Bayside PSD permit. For Bayside Power Station (BPS) Unit 1, that is the RATA and stratification may be performed, on the following dates and order:

BPS 1A- April 09, 2003
BPS 1B- April 08, 2003
BPS 1C- April 07, 2003

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034. Please let me know if you receive this message.

Sincerely,

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

TAMPA ELECTRIC

March 6, 2003

RECEIVED
MAR 17 2003
BUREAU OF AIR REGULATION

Mr. Lynn Haynes
Region IV
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7922 0359 4686

Ms. Trina Vielhauer
Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7928 4431 0191

Re: **Tampa Electric Company**
Bayside Power Station Unit 1
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Haynes and Ms. Vielhauer:

Tampa Electric Company (TEC) is in the process of starting up Bayside Power Station Unit 1. Enclosed is the Test Protocol that TEC will be use to perform the initial compliance testing and the initial Continuous Emissions Monitoring System certification.

If you have any questions, please call Dru Latchman or me at (813) 641-5034.

Sincerely,

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

EA/bmr/DNL155

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP (enc)
Kim Nguyen – CAMD (enc)
Mr. S. Sheplak- FDEP
Mr. S. Woodard- EPCHC (enc)

TAMPA ELECTRIC

RECEIVED

MAR 17 2003

BUREAU OF AIR REGULATION

March 4, 2003

Mr. Lynn Haynes
Region IV
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7902 2109 6990

Ms. Trina Vielhauer
Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7913 1274 5011

Re: Tampa Electric Company
Bayside Power Station Unit 1
Initial Certification Testing
Air Permit No. PSD-FL-301A
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Hayes and Ms. Vielhauer:

Tampa Electric Company (TEC) is re-notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the initial Continuous Emissions Monitoring System (CEMS) certification test. The initial CEMS test being performed are the cylce response time test, linearity and drift test. TEC hereby gives notice that the initial CEMS certification test may be performed for Bayside Power Station (BPS) Unit 1, that is the cycle response time test, linearity and drift test, on the following dates:

BPS 1A- March 16, 2003
BPS 1B- March 11, 2003
BPS 1C- March 06, 2003

The RATA and stratification will be performed with the initial compliance test required by 40 CFR 60 and Bayside PSD permit. For Bayside Power Station (BPS) Unit 1, that is the RATA and stratification may be performed, on the following dates and order:

BPS 1A- April 09, 2003
BPS 1B- April 08, 2003
BPS 1C- April 07, 2003

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034.

Sincerely,

Dru Latchman

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

EA/bmr/DNL153

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC
Mr. J. Kahn - FDEP
Kim Nguyen - CAMD
Mr. S. Sheplak – FDEP

-R-
spread comp...

TAMPA ELECTRIC

RECEIVED

MAR 14 2003

BUREAU OF AIR REGULATION

March 13, 2003

Mr. Scott Sheplak, P.E.
Administrator- Title V Section
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7902 3003 4520

Re: Tampa Electric Company
Bayside Power Station Unit 1
Initial Startup Notification
Air Permit No. PSD-FL-301A
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Sheplak:

Tampa Electric Company (TEC) is notifying the Florida Department of Environmental Protection (FDEP) the initial startup occurred at Bayside Power Station Unit 1 (BPS). BPS Unit 1 is made up of three Gas Turbine's (GT), Bayside 1A, 1B, and 1C, has a 150 foot stack and is connected to its own Heat Recovery Steam Generator. TEC is giving notification that the GTs were started in the following order and dates:

BPS 1A- March 12, 2003
BPS 1B- March 10, 2003
BPS 1C- March 09, 2003

If you have any questions, please call me at (813) 641-5034.

Sincerely,

Dru Latchman

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

EA/bmr/DNL156

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC

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

-file-

General correspondence

TECO

TAMPA ELECTRIC

RECEIVED

MAR 05 2003

BUREAU OF AIR REGULATION

March 4, 2003

Mr. Scott Sheplak, P.E.
Administrator- Title V Section
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7915 4668 0632

Re: Tampa Electric Company
Bayside Power Station Unit 1
Anticipated Startup Notification
Air Permit No. PSD-FL-301A
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Sheplak:

Tampa Electric Company (TEC) is re-notifying the Florida Department of Environmental Protection (FDEP) of the anticipated date of initial startup. TEC hereby gives notice that the anticipated startup of Bayside Power Station Unit 1 will be on March 6, 2003. Bayside Power Station Unit 1 (BPS) consists of three General Electric PG7241FA, 169 megawatt Gas Turbines (GT) at its BPS facility. Each of these three GT's, Bayside 1A, 1B, and 1C, has a 150 foot stack and is connected to its own Heat Recovery Steam Generator. Since it is still uncertain in which order the GTs will be started, TEC is giving notification that the GTs may start in the following order and dates:

BPS 1A- March 16, 2003
BPS 1B- March 11, 2003
BPS 1C- March 06, 2003

As the schedule changes TEC will keep FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034.

Sincerely,

Dru Latchman

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

EA/bmr/DNL152

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC

Fil
general correspondence

TAMPA ELECTRIC

RECE ED
JAN 31 2003
BUREAU OF AIR REGULATION

January 27, 2003

Mr. Lynn Haynes
Region IV
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7921 7627 9132

Ms. Trina Vielhauer
Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7912 8433 0209

Re: Tampa Electric Company
Bayside Power Station Unit 1
Anticipated Commercial Operations Notification
Oris Code # 7873

Dear Mr. Hayes and Ms. Vielhauer:

Tampa Electric Company (TEC) is notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the anticipated date of initial commercial operations as required by 40 CFR 75.61(a)(2)(i), the designated representative for an affected unit shall submit written notification: For a new unit or a newly affected unit, of the planned date when a new unit or newly affected unit will commence commercial operation or, for new stack or flue gas desulfurization system, of the planned date when a new stack or flue gas desulfurization system will be completed and emissions will first exit to the atmosphere. Notification of the planned date shall be submitted not later than 45 days prior to the date the unit commences commercial operation, or not later than 45 days prior to the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere. TEC hereby gives notice of commercial operation, for environmental purposes, of Bayside Power Station Unit 1 will be on or about March 14, 2003. Bayside Power Station Unit 1 (BPS) consists of three General Electric PG7241FA, 169 megawatt Gas Turbines (GT) at the BPS facility. Each of these three GT's, Bayside 1A, 1B, and 1C, has a 150 foot stack and is connected to its own Heat Recovery Steam Generator. Since it is still uncertain in which order the GTs will begin commercial operations, TEC is giving notification that the GTs may commence commercial operations in the following order and on or about the following dates:

BPS 1A - March 14, 2003
BPS 1B - March 19, 2003
BPS 1C - March 24, 2003

TAMPA ELECTRIC COMPANY
P. O. BOX 111 TAMPA, FL 33601-0111
(813) 228-4111

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

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

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034.

Sincerely,

Dru Latchman

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

EA/bmr/DNL147

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC
Mr. S. Sheplak- FDEP

file
general correspondence

TEC☉

TAMPA ELECTRIC

RECEIVED

JAN 13 2003

BUREAU OF AIR REGULATION

January 10, 2003

Mr. Scott Sheplak, P.E.
Administrator- Title V Section
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7928 0550 7046

Re: Tampa Electric Company
Bayside Power Station Unit 1
Anticipated Startup Notification

Dear Mr. Sheplak:

Tampa Electric Company (TEC) is notifying the Florida Department of Environmental Protection (FDEP) of the anticipated date of initial startup as required by 40 CFR Part 52.129(c)(7)(i), which states that the anticipated date of initial startup of a source must be done not more than 60 days or less than 30 days prior to initial startup. TEC hereby gives notice that the anticipated startup of Bayside Power Station Unit 1 will be on March 5, 2003. Bayside Power Station Unit 1 (BPS) consists of three General Electric PG7241FA, 169 megawatt Gas Turbines (GT) at its BPS facility. Each of these three GT's, Bayside 1A, 1B, and 1C, has a 150 foot stack and is connected to its own Heat Recovery Steam Generator. Since it is still uncertain in which order the GTs will be started, TEC is giving notification that the GTs may start in the following order and dates:

BPS 1A – March 5, 2003
BPS 1B- March 10, 2003
BPS 1C- March 15, 2003

Hence the reason BPS 1B and 1C's anticipated initial startup date is being notified in a timeframe greater than 60 days as required by 40 CFR Part 52.129(c)(7)(i). As the schedule changes TEC will keep FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034.

Sincerely,

Dru Latchman

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

EA/bmr/DNL145

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC

TAMPA ELECTRIC

RECEIVED
FEB 10 2003
BUREAU OF AIR REGULATION

January 31, 2003

Mr. Lynn Haynes
Region IV
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7901 9588 1500

Ms. Trina Vielhauer
Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7915 2562 0812

Re: Tampa Electric Company
Bayside Power Station Unit 1
Initial ComplianceTesting
Air Permit No. PSD-FL-301A
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Hayes and Ms. Vielhauer:

Tampa Electric Company (TEC) is notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the initial compliance testing. As required by 40 CFR Part 60.8(a) and Condition 20 of permit PSD-Fl-301A, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s). Also as required by 40 CFR Part 60.8(d) and Condition 20 of permit PSD-FL-301A, the owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test. TEC hereby gives notice that the initial compliance test may be performed for Bayside Power Station (BPS) Unit 1 on the following dates:

BPS 1A - April 7, 2003
BPS 1B - April 8, 2003
BPS 1C - April 9, 2003

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034.

Sincerely,

Dru Latchman

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

EA/bmr/DNL149

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC
Mr. J. Kahn - FDEP
Kim Nguyen – CAMD
Mr. S. Sheplak – FDEP

TAMPA ELECTRIC

RECEIVED

FEB 10 2003

BUREAU OF AIR REGULATION

January 31, 2003

Mr. Lynn Haynes
Region IV
U.S. Environmental Protection Agency
Atlanta Federal Center
61 Forsyth Street
Atlanta, Georgia 30303-3104

Via FedEx
Airbill No. 7901 9588 1500

Ms. Trina Vielhauer
Bureau Chief
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7915 2562 0812

Re: Tampa Electric Company
Bayside Power Station Unit 1
Initial Certification Testing
Air Permit No. PSD-FL-301A
Project No. 0570040-15-AC, ORIS code #7873

Dear Mr. Hayes and Ms. Vielhauer:

Tampa Electric Company (TEC) is notifying the Environmental Protection Agency (EPA) and Florida Department of Environmental Protection (FDEP) of the initial Continuous Emissions Monitoring System (CEMS) certification test as required by 40 CFR Part 75.61(a)(1)(i), which states initial certification test notifications shall be submitted not later than 21 days prior to the first scheduled day of initial certification testing. TEC hereby gives notice that the initial CEM certification test may be performed for Bayside Power Station (BPS) Unit 1 on the following dates:

BPS 1A - March 05, 2003
BPS 1B - March 10, 2003
BPS 1C - March 15, 2003

As the schedule changes TEC will keep EPA and FDEP updated. TEC appreciates your cooperation in this matter and if you have any questions, please call me at (813) 641-5034.

Sincerely,

Dru Latchman

Dru Latchman
Associate Engineer- Air Programs
Environmental Affairs

EA/bmr/DNL

c: Mr. A. Linero – FDEP
Mr. J. Kissel – FDEP SW
Mr. S. Woodard- EPCHC
Mr. J. Kahn - FDEP
Kim Nguyen - CAMD
Mr. S. Sheplak – FDEP

Table 6-1. Air Quality Impact Analysis Summary
Natural Gas-Firing (Page 3 of 3)

	Case 9 (50% Load, 72°F Ambient)					Case 10 (100% Load, 93°F Ambient)					Case 11 (75% Load, 93°F Ambient)					Case 12 (50% Load, 93°F Ambient)					Maximums
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	
Nominal 10 g/s Impacts:																					
HSH, 1-Hour (μg/m^3)	1,020.5	958.9	970.7	1,007.7	944.6	691.0	694.0	685.8	687.5	670.7	856.8	796.4	809.1	842.8	798.4	**1,035.7**	974.2	985.9	1,023.1	958.2	**1,035.7**
HSH, 3-Hour (μg/m^3)	560.1	**623.6**	612.2	600.5	598.0	480.4	506.2	486.1	506.2	494.4	535.8	546.4	527.8	541.1	559.8	563.5	560.3	619.9	604.7	601.8	**623.6**
HSH, 8-Hour (μg/m^3)	285.9	297.6	376.0	359.8	326.3	237.9	258.2	291.0	314.6	302.1	275.2	261.6	347.7	341.0	334.6	290.0	311.8	**378.5**	367.9	310.8	**378.5**
HSH, 24-Hour (μg/m^3)	185.9	181.0	200.4	237.3	229.1	158.7	138.3	139.5	175.5	165.2	178.4	171.2	170.0	222.8	205.6	187.4	184.0	204.4	**241.3**	232.9	**241.3**
Annual (μg/m^3)	16.7	13.3	16.8	16.8	22.2	9.4	7.5	10.7	10.2	13.1	13.3	10.6	14.3	14.0	18.5	17.2	13.6	17.1	17.1	**22.7**	**22.7**
SO_2																					
Emission Rate (g/s)	0.83	0.83	0.83	0.83	0.83	1.23	1.23	1.23	1.23	1.23	0.98	0.98	0.98	0.98	0.98	0.79	0.79	0.79	0.79	0.79	**1.4**
HSH, 3-Hour (μg/m^3)	46.5	51.8	50.8	83.6	49.6	59.1	62.3	59.8	62.3	60.8	52.5	53.6	51.7	82.6	54.9	44.5	44.3	49.0	80.8	47.5	**91.3**
HSH, 24-Hour (μg/m^3)	15.4	15.0	16.6	19.7	19.0	19.5	17.0	17.2	21.6	20.3	17.5	16.8	16.7	21.8	20.1	14.8	14.5	16.1	19.1	18.4	**22.9**
Annual (μg/m^3)	1.4	1.1	1.4	1.4	1.8	1.2	0.9	1.3	1.3	1.6	1.3	1.0	1.4	1.4	1.8	1.4	1.1	1.4	1.4	1.8	**2.0**
NO_2																					
Emission Rate (g/s)	1.81	1.81	1.81	1.81	1.81	2.76	2.76	2.76	2.76	2.76	2.17	2.17	2.17	2.17	2.17	1.73	1.73	1.73	1.73	1.73	**3.1**
Tier 2 Annual (μg/m^3)	2.3	1.8	2.3	2.3	3.0	1.9	1.5	2.2	2.1	2.7	2.2	1.7	2.3	2.3	3.0	2.2	1.8	2.2	2.2	2.9	**3.3**
PM/PM_{10}																					
Emission Rate (g/s)	2.46	2.46	2.46	2.46	2.46	2.55	2.55	2.55	2.55	2.55	2.48	2.48	2.48	2.48	2.48	2.44	2.44	2.44	2.44	2.44	**2.6**
HSH, 24-Hour (μg/m^3)	45.7	44.5	49.3	58.4	56.4	40.5	35.3	35.6	44.8	42.1	44.2	42.4	42.2	55.3	51.0	45.7	44.9	49.9	**58.9**	56.8	**58.9**
Annual (μg/m^3)	4.1	3.3	4.1	4.1	5.5	2.4	1.9	2.7	2.6	3.4	3.3	2.6	3.6	3.5	4.6	4.2	3.3	4.2	4.2	**5.5**	**5.5**
CO																					
Emission Rate (g/s)	2.41	2.41	2.41	2.41	2.41	3.39	3.39	3.39	3.39	3.39	2.76	2.76	2.76	2.76	2.76	2.34	2.34	2.34	2.34	2.34	**3.9**
HSH, 1-Hour (μg/m^3)	245.9	231.1	233.9	242.9	227.6	234.3	235.3	232.5	233.1	227.4	236.5	219.8	223.3	232.6	220.4	242.4	228.0	230.7	239.4	224.2	**261.5**
HSH, 8-Hour (μg/m^3)	68.9	71.7	90.6	86.7	78.6	80.7	87.5	98.6	106.7	102.4	76.0	72.2	96.0	94.1	92.3	67.9	73.0	88.6	86.1	72.7	**174.8**

	Project Impact	Case No.	Year	Florida AAQS	Federal NAAQS	% of AAQS Florida	% of AAQS Federal
SO_2							
HSH, 3-Hour (μg/m^3)	91.3	3	1995	1,300	1,300	7.0	7.0
HSH, 24-Hour (μg/m^3)	22.9	5	1995	260	365	8.8	6.3
Annual (μg/m^3)	2.0	3	1996	60	80	3.3	2.5
NO_2							
Annual (μg/m^3)	3.3	3	1996	100	100	3.3	3.3
PM_{10}							
HSH, 24-Hour (μg/m^3)	58.9	12	1995	150	150	39.3	39.3
Annual (μg/m^3)	5.5	12	1996	50	50	11.1	11.1
CO							
HSH, 1-Hour (μg/m^3)	261.5	3	1992	40,000	40,000	0.7	0.7
HSH, 8-Hour (μg/m^3)	174.8	7	1995	10,000	10,000	1.7	1.7

Source: ECT, 2001.

Table 6-1. Air Quality Impact Analysis Summary
Natural Gas-Firing (Page 2 of 3)

	Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)					Case 7 (100% Load, 72°F Ambient)					Case 8 (75% Load, 72°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts:																				
HSH, 1-Hour ($\mu g/m^3$)	807.0	774.2	765.4	792.4	760.9	1,016.6	954.7	966.7	1,003.6	940.7	681.5	685.4	679.6	675.7	662.6	819.4	777.8	772.3	805.1	765.9
HSH, 3-Hour ($\mu g/m^3$)	543.2	570.4	509.4	541.6	534.7	559.3	622.7	610.2	599.4	596.9	470.8	501.0	477.1	499.5	483.7	546.3	572.6	514.8	546.4	541.1
HSH, 8-Hour ($\mu g/m^3$)	272.2	285.1	355.2	358.3	333.4	284.7	294.9	375.4	358.9	326.0	235.4	254.5	285.1	311.3	297.7	273.6	286.2	357.5	360.3	335.0
HSH, 24-Hour ($\mu g/m^3$)	174.7	169.5	164.1	216.3	199.4	187.6	180.6	199.4	236.7	228.4	152.8	134.2	135.5	169.8	160.7	175.8	170.9	165.6	218.0	201.3
Annual ($\mu g/m^3$)	12.4	10.0	13.6	13.2	17.4	16.6	13.2	16.7	16.7	22.1	8.9	7.0	10.4	9.8	12.6	12.6	10.2	13.7	13.4	17.7
SO_2																				
Emission Rate (g/s)	1.06	1.06	1.06	1.06	1.06	0.85	0.85	0.85	0.85	0.85	1.27	1.27	1.27	1.27	1.27	1.03	1.03	1.03	1.03	1.03
HSH, 3-Hour ($\mu g/m^3$)	57.6	60.5	54.0	57.4	56.7	47.5	52.9	51.9	85.3	50.7	59.8	63.6	60.6	85.8	61.4	56.3	59.0	53.0	82.9	55.7
HSH, 24-Hour ($\mu g/m^3$)	18.5	18.0	17.4	**22.9**	21.1	15.9	15.3	17.0	20.1	19.4	19.4	17.0	17.2	21.6	20.4	18.1	17.6	17.1	22.5	20.7
Annual ($\mu g/m^3$)	1.3	1.1	1.4	1.4	1.8	1.4	1.1	1.4	1.4	1.9	1.1	0.9	1.3	1.3	1.6	1.3	1.0	1.4	1.4	1.8
NO_2																				
Emission Rate (g/s)	2.36	2.36	2.36	2.36	2.36	1.86	1.86	1.86	1.86	1.86	2.85	2.85	2.85	2.85	2.85	2.29	2.29	2.29	2.29	2.29
Tier 2 Annual ($\mu g/m^3$)	2.2	1.8	2.4	2.3	3.1	2.3	1.8	2.3	2.3	3.1	1.9	1.5	2.2	2.1	2.7	2.2	1.7	2.4	2.3	3.0
PM/PM_{10}																				
Emission Rate (g/s)	2.51	2.51	2.51	2.51	2.51	2.46	2.46	2.46	2.46	2.46	2.56	2.56	2.56	2.56	2.56	2.49	2.49	2.49	2.49	2.49
HSH, 24-Hour ($\mu g/m^3$)	43.8	42.5	41.2	54.3	50.0	46.1	44.4	49.1	58.2	56.2	39.1	34.4	34.7	43.5	41.1	43.8	42.5	41.2	54.3	50.1
Annual ($\mu g/m^3$)	3.1	2.5	3.4	3.3	4.4	4.1	3.2	4.1	4.1	5.4	2.3	1.8	2.7	2.5	3.2	3.1	2.5	3.4	3.3	4.4
CO																				
Emission Rate (g/s)	2.96	2.96	2.96	2.96	2.96	2.46	2.46	2.46	2.46	2.46	3.50	3.50	3.50	3.50	3.50	2.87	2.87	2.87	2.87	2.87
HSH, 1-Hour ($\mu g/m^3$)	238.9	229.2	226.5	234.6	225.2	250.1	234.8	237.8	246.9	231.4	238.5	239.9	237.9	236.5	231.9	235.2	223.2	221.6	231.1	219.8
HSH, 8-Hour ($\mu g/m^3$)	80.6	84.4	105.2	160.3	98.7	70.0	72.5	92.3	88.3	80.2	82.4	89.1	99.8	**174.8**	104.2	78.5	82.1	102.6	103.4	96.1

Table 6-1. Air Quality Impact Analysis Summary
Natural Gas-Firing (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
Nominal 10 g/s Impacts:																				
HSH, 1-Hour ($\mu g/m^3$)	621.3	625.4	632.3	613.1	615.7	739.9	743.9	735.2	747.8	732.4	1,017.5	953.4	966.4	1,003.4	939.3	675.8	680.6	676.7	670.1	658.9
HSH, 3-Hour ($\mu g/m^3$)	411.7	463.2	419.9	450.2	431.8	526.1	575.2	481.0	521.9	510.0	559.5	622.9	610.1	599.3	596.0	466.2	498.5	472.4	496.3	478.0
HSH, 8-Hour ($\mu g/m^3$)	227.7	251.6	264.5	275.8	267.6	258.7	275.5	322.6	336.6	325.3	284.4	292.7	375.8	358.7	325.8	234.2	252.8	282.0	309.7	295.7
HSH, 24-Hour ($\mu g/m^3$)	125.5	109.8	121.1	151.0	136.2	169.8	158.9	159.3	201.9	191.5	186.4	180.9	199.2	236.6	227.9	150.0	132.3	133.5	168.5	158.3
Annual ($\mu g/m^3$)	7.0	5.2	8.2	7.7	9.6	11.5	9.3	12.7	12.3	16.1	16.6	13.2	16.7	16.7	22.0	8.7	6.9	10.2	9.7	12.4
SO_2																				
Emission Rate (g/s)	1.39	1.39	1.39	1.39	1.39	1.13	1.13	1.13	1.13	1.13	0.91	0.91	0.91	0.91	0.91	1.30	1.30	1.30	1.30	1.30
HSH, 3-Hour ($\mu g/m^3$)	57.2	64.4	58.4	62.6	60.0	59.4	65.0	54.3	84.5	57.6	50.9	56.7	55.5	91.3	54.2	60.6	64.8	61.4	64.5	62.1
HSH, 24-Hour ($\mu g/m^3$)	17.5	15.3	16.8	21.0	18.9	19.2	18.0	18.0	22.8	21.6	17.0	16.5	18.1	21.5	20.7	19.5	17.2	17.4	21.9	20.6
Annual ($\mu g/m^3$)	1.0	0.7	1.1	1.1	1.3	1.3	1.0	1.4	1.4	1.8	1.5	1.2	1.5	1.5	2.0	1.1	0.9	1.3	1.3	1.6
NO_2																				
Emission Rate (g/s)	3.11	3.11	3.11	3.11	3.11	2.51	2.51	2.51	2.51	2.51	1.99	1.99	1.99	1.99	1.99	2.91	2.91	2.91	2.91	2.91
Tier 2 Annual ($\mu g/m^3$)	1.6	1.2	1.9	1.8	2.2	2.2	1.7	2.4	2.3	3.0	2.5	2.0	2.5	2.5	3.3	1.9	1.5	2.2	2.1	2.7
PM/PM_{10}																				
Emission Rate (g/s)	2.58	2.58	2.58	2.58	2.58	2.52	2.52	2.52	2.52	2.52	2.47	2.47	2.47	2.47	2.47	2.56	2.56	2.56	2.56	2.56
HSH, 24-Hour ($\mu g/m^3$)	32.4	28.3	31.2	39.0	35.1	42.8	40.0	40.1	50.9	48.3	46.0	44.7	49.2	58.4	56.3	38.4	33.9	34.2	43.1	40.5
Annual ($\mu g/m^3$)	1.8	1.4	2.1	2.0	2.5	2.9	2.3	3.2	3.1	4.1	4.1	3.3	4.1	4.1	5.4	2.2	1.8	2.6	2.5	3.2
CO																				
Emission Rate (g/s)	3.92	3.92	3.92	3.92	3.92	3.10	3.10	3.10	3.10	3.10	2.57	2.57	2.57	2.57	2.57	3.62	3.62	3.62	3.62	3.62
HSH, 1-Hour ($\mu g/m^3$)	243.5	245.1	247.9	240.3	241.3	229.4	230.6	227.9	231.8	227.0	261.5	245.0	248.4	257.9	241.4	244.6	246.4	245.0	242.6	238.5
HSH, 8-Hour ($\mu g/m^3$)	89.3	98.6	103.7	108.1	104.9	80.2	85.4	100.0	104.3	100.8	73.1	75.2	96.6	92.2	83.7	84.8	91.5	102.1	112.1	107.0

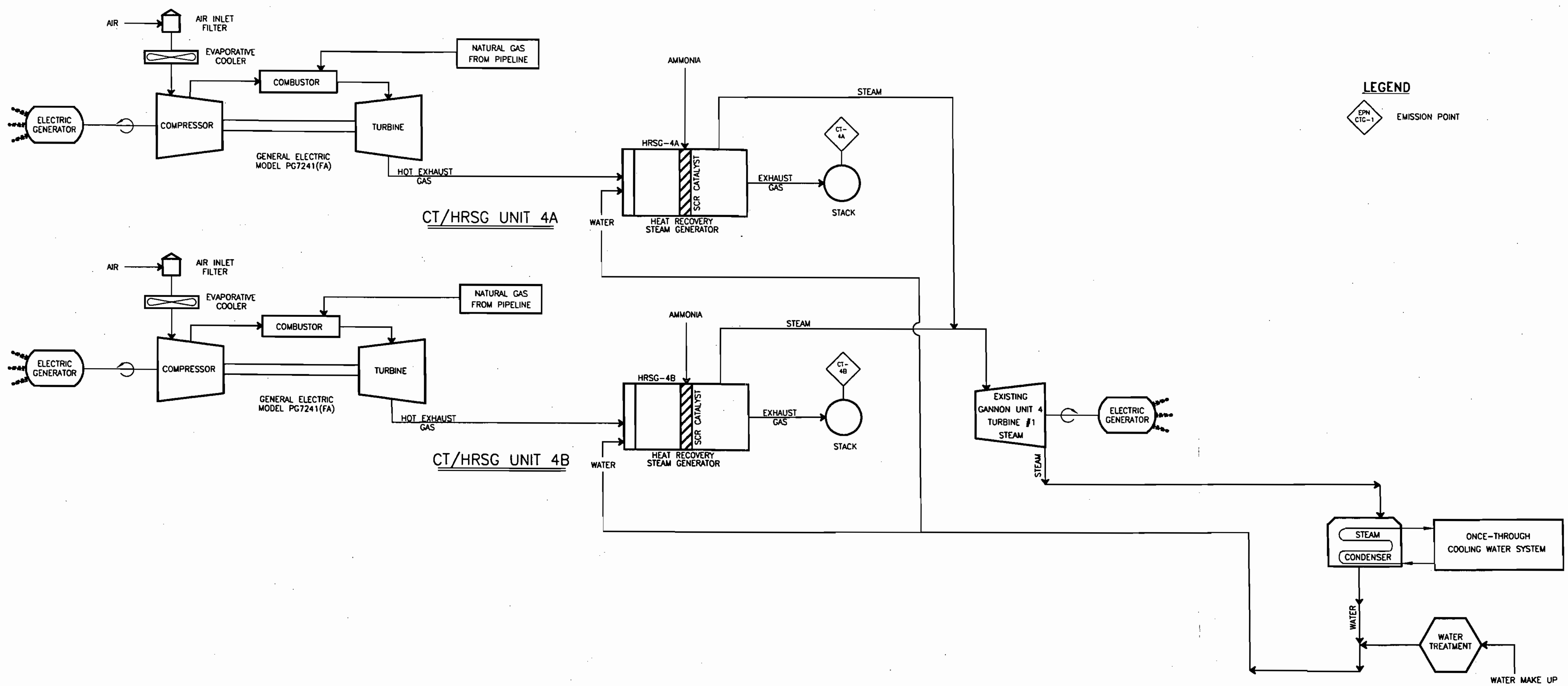


FIGURE 2-5.
PROCESS FLOW DIAGRAM - BAYSIDE UNIT 4

Source: TEC, 2001; ECT, 2001.

TECO
TAMPA ELECTRIC

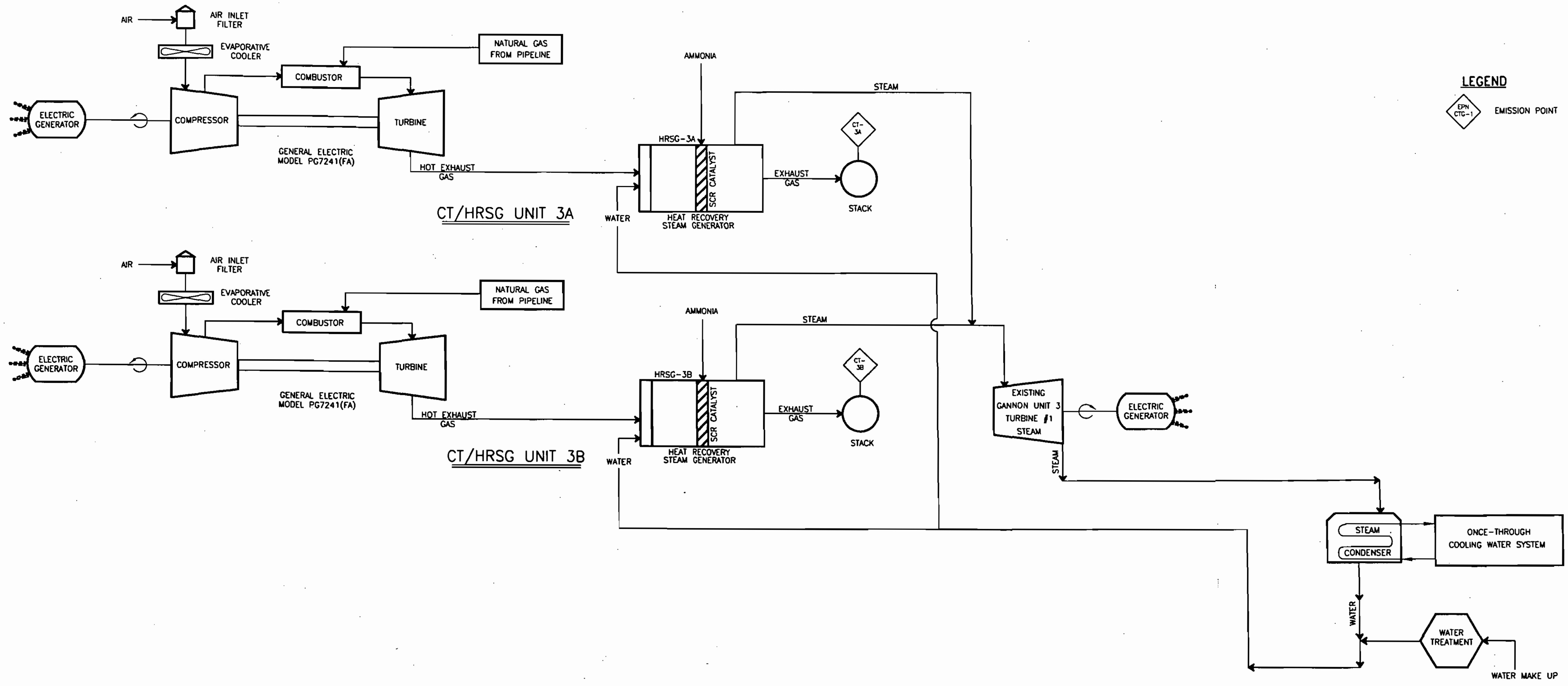
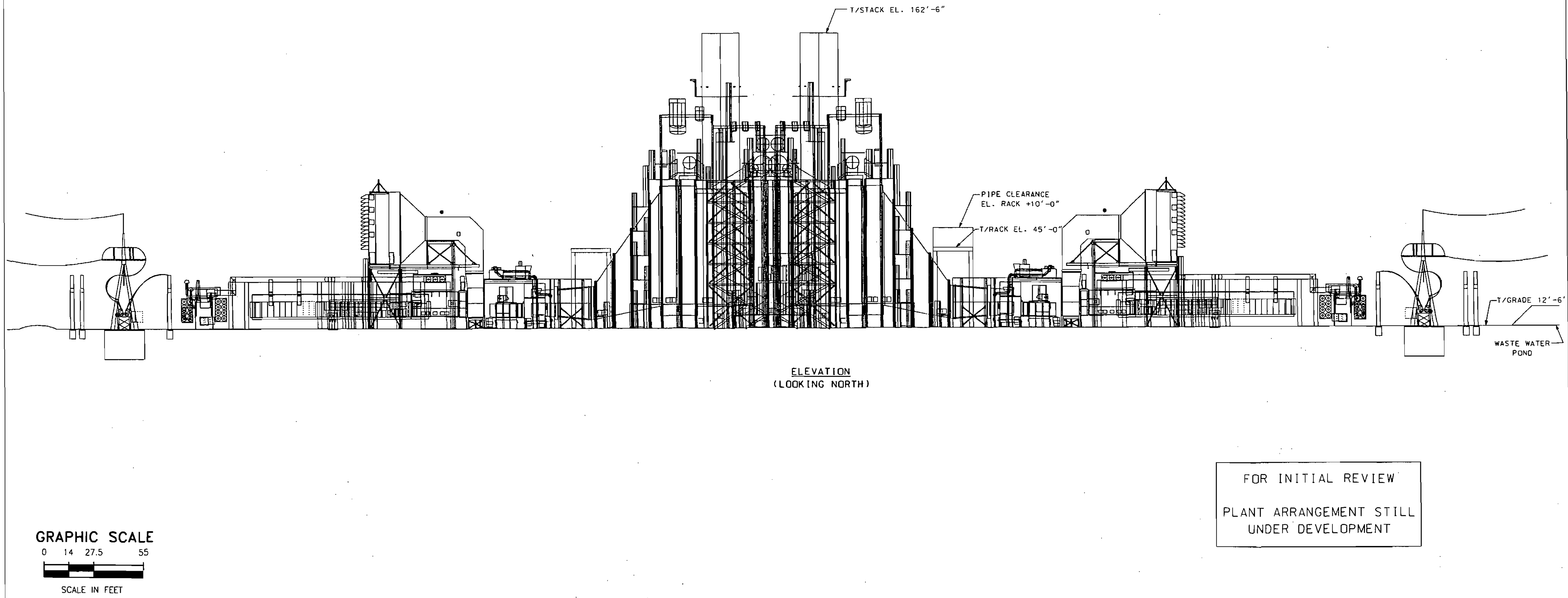


FIGURE 2-4.
PROCESS FLOW DIAGRAM - BAYSIDE UNIT 3

Source: TEC, 2001; ECT, 2001.

TECO
TAMPA ELECTRIC



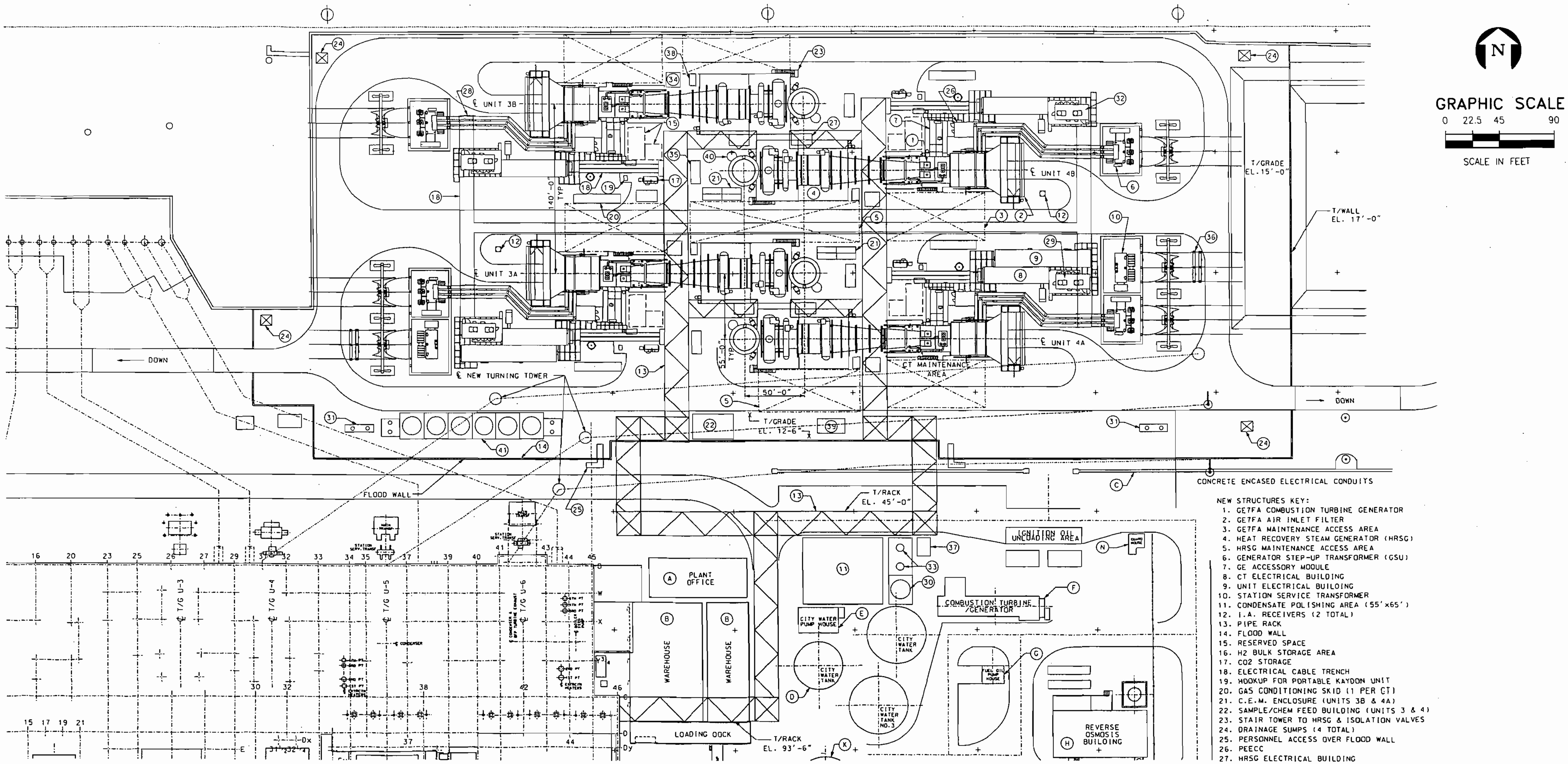
FOR INITIAL REVIEW

PLANT ARRANGEMENT STILL UNDER DEVELOPMENT

FIGURE 2-3.
BAYSIDE UNITS 3 AND 4 PROFILE

SOURCE: Sargent & Lundy, 2001.

TECO
TAMPA ELECTRIC



NEW STRUCTURES KEY:

1. GE7FA COMBUSTION TURBINE GENERATOR
2. GE7FA AIR INLET FILTER
3. GE7FA MAINTENANCE ACCESS AREA
4. HEAT RECOVERY STEAM GENERATOR (HRSG)
5. HRSG MAINTENANCE ACCESS AREA
6. GENERATOR STEP-UP TRANSFORMER (GSU)
7. GE ACCESSORY MODULE
8. CT ELECTRICAL BUILDING
9. UNIT ELECTRICAL BUILDING
10. STATION SERVICE TRANSFORMER
11. CONDENSATE POLISHING AREA (55'x65')
12. I.A. RECEIVERS (2 TOTAL)
13. PIPE RACK
14. FLOOD WALL
15. RESERVED SPACE
16. H2 BULK STORAGE AREA
17. CO2 STORAGE
18. ELECTRICAL CABLE TRENCH
19. HOOKUP FOR PORTABLE KAYDON UNIT
20. GAS CONDITIONING SKID (1 PER CT)
21. C.E.M. ENCLOSURE (UNITS 3B & 4A)
22. SAMPLE/CHEM FEED BUILDING (UNITS 3 & 4)
23. STAIR TOWER TO HRSG & ISOLATION VALVES
24. DRAINAGE SUMPS (4 TOTAL)
25. PERSONNEL ACCESS OVER FLOOD WALL
26. PEECC
27. HRSG ELECTRICAL BUILDING
28. BAC
29. LCI & EX2100 (UNITS 3B & 4B)
30. POLISHER WASTE WATER TANK
31. OIL/WATER SEPRATORS (2 TOTAL)
32. EX2100 (UNITS 3A & 4A)
33. ACID & CAUSTIC TANKS
34. METAL CLEANING SUMP
35. FEEDWATER PUMP
36. TRANSMISSION CCVT (UNITS 3B & 4B)
37. AMINE SKIDS
38. SCR SKID
39. WATER WASH SKID (UNITS 3A & 4B)
40. BLOWDOWN TANK
41. CCW COOLING TOWERS

FOR INITIAL REVIEW

PLANT ARRANGEMENT STILL UNDER DEVELOPMENT

HRSG STACK LOCATIONS				
UNIT	PLANT COORDINATES		STATE COORDINATES	
	NORTH	EAST	NORTH	EAST
3A	1700	3660	1299632.5650	520242.0058
3B	1840	3660	1299772.5622	520242.8847
4A	1645	3610	1299577.8800	520191.6614
4B	1785	3610	1299717.8772	520192.5404

EXISTING STRUCTURES KEY:

A. PLANT OFFICE
B. WAREHOUSE
C. COVERED CABLE CONCRETE TRENCH
D. CITY WATER TANKS
E. CITY WATER PUMP HOUSE
F. COMBUSTION TURBINE/GENERATOR
G. FUEL OIL PUMP HOUSE
H. REVERSE OSMOSIS BUILDING
I. NOT USED
J. NOT USED
K. RECYCLE WATER TANK
L. BOILER SHOP
M. NOT USED
N. GUARD HOUSE
O. NOT USED
P. NOT USED
R. NOT USED
S. NOT USED

FIGURE 2-2.
BAYSIDE UNITS 3 AND 4 PLOT PLAN

SOURCE: Sorgent & Lundy, 2001.

TECO
TAMPA ELECTRIC

7000 0600 0026 4129 9150

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

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

Postmark Here

Recipient's Name (Please Print Clearly) (to be completed by mailer)
Ms. Karen Sheffield, Gen. Mgr.
Street, Apt. No.; or PO Box No.
Port sutton Rd.
City, State, ZIP+4
Tampa, FL 33619

PS Form 3800, February 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:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Joseph Hernandez
B. Date of Delivery 7-19-01

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

2 Article Number *(Copy from service label)*
7000 0600 0026 4129 9150

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

UNITED STATES POSTAL SERVICE

TAMPA, FL 336
PM
13 JUL
2001

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

RECEIVED
JUL 23 2001
BUREAU OF AIR REGULATION

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

7000 0600 0026 4129 9242

TAMPA FL 33619

Postage	$ $0.34
Certified Fee	$2.10
Return Receipt Fee (Endorsement Required)	$1.50
Restricted Delivery Fee (Endorsement Required)	$0.00
Total Postage & Fees	$ $3.94

0682
04
Postmark Here
TALLAHASSEE FL
CENTER
JUL 26 2001
07/26/2001

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

PS Form 3800, February 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:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* A Noel
B. Date of Delivery 7-28-01

C. Signature
X Alphaeus Noel
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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

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

2 Article Number *(Copy from service label)*
7000 0600 0026 4129 9242

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

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

RECEIVED
JUL 30 2001
BUREAU OF AIR REGULATION

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

7000 2870 0000 7028 2935

OFFICIAL USE

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

Postmark Here

Sent To
Karen Sheffield
Street, Apt. No.; or PO Box No.
Port Sutton Road
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:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 11/28/01
C. Signature
X Ron Tietbohl ☐ Agent ☐ Addressee
D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No
RON TIETBOHL

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 2935

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

UNITED STATES POSTAL SERVICE

TAMPA, FL

PM

29 NOV

200

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

RECEIVED

DEC 03 2001

BUREAU OF AIR REGULATION

THE TAMPA TRIBUNE RECEIVED

Published Daily

Tampa, Hillsborough County, Florida DEC 05 2001

State of Florida }

County of Hillsborough } ss.

BUREAU OF AIR REGULATION

Before the undersigned authority personally appeared J. Rosenthal, who on oath says that she is Classified Billing Manager 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 NOVEMBER 30, 2001

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.

J Rosenthal

Sworn to and subscribed by me, this 30 day

of NOVEMBER, A.D. 20 01

Personally Known ✓ or Produced Identification ______

Type of Identification Produced ______

NOTARY PUBLIC STATE OF FLORIDA
OFFICIAL NOTARY SEAL
SUSIE LEE SLATON
COMMISSION NUMBER
DD000060
MY COMMISSION EXP.
APRIL 16, 2005

Susie Lee Slaton

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Tampa Electric Company
Bayside Power Station, Gannon Re-Powering Project
Project No. 0570040-015-AC
Draft Permit PSD-FL-301A

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Tampa Electric Company to re-power the existing F. J. Gannon power plant on Tampa's Port Sutton Road in Hillsborough County, Florida. The re-powered plant will be renamed the Bayside Power Station and will have a nominal electrical production capacity of 2845 MW. The applicant's authorized representative is Ms. Karen Sheffield, the General Manager of the Bayside Power Station. The applicant's mailing address is Bayside Power Station, Port Sutton Road, Tampa, FL 33619.

The applicant proposes to re-power the existing Gannon Station with eleven new combined cycle gas turbines. Each new unit will consist of a nominal 170 MW General Electric Model PG7241(FA) gas turbine with heat recovery steam generator. The new combined cycle units will be grouped to re-power the existing steam-electric turbines for existing Gannon Units 3,4,5, and 6. The re-powering project will increase the nominal electrical generating capacity of this plant to 2845 MW. The overall thermal efficiency of the plant is predicted to increase from approximately 30% to 55%. All existing Gannon coal-fired boilers will be shut down prior to January 1, 2005.

Because the existing plant is a PSD-major source of air pollution, new projects are subject to the preconstruction review requirements for the Prevention of Significant Deterioration (PSD) of Air Quality in Rule 62-212.400, F.A.C. The re-powering project will result in the following potential annual emissions: 1383 tons per year of carbon monoxide; 1113 tons per year of nitrogen oxides (NOx), 1.4 tons per year of lead, 368 tons per year of particulate matter (PM/PM10), 89 tons per year of sulfuric acid mist (SAM), 487 tons per year sulfur dioxide (S02), and 135 tons per year of volatile organic compounds (VOC). The project is significant for emissions of CO, PM/PM10, and VOC. Due to the large emissions reductions from the shutdown of the existing coal-fired boilers, the projec[t] nets out of PSD review fo[r] emissions of NOx SAM, an[d] SO2. After the shutdown o[f] all coal-fired units, the re-powering project will reduce emissions of: nitrogen oxides by more tha[n] 28,000 tons per year; particulate matter by mor[e] than 1600 tons per yea[r]; sulfur dioxide by more tha[n] 60,000 tons per year; sulfuric acid mist by more tha[n] 900 tons per year; and lea[d] by more than 18 tons pe[r] year.

The Department is required to determine the Best Available Control Technology (BACT) for the significant emissions of CO, PM/PM10, and VOC. For each of these pollutants, BACT is determined to be the efficient combustion design and exclusive firing of pipeline-quality natural gas. A continuous emissions monitoring system (CEMS) will be used to demonstrate compliance with the CO emissions standards and serve as an indicator of efficient combustion to minimize emissions of PM/PM10 and VOC.

The gas turbines incorporate dry low-NOx combustion technology and automated controls to minimize NOx emissions. The state and federal settlement agreements require the installation of a selective catalytic reduction (SCR) system to reduce NOx emissions. A continuous emissions monitoring system (CEMS) is required for acid rain monitoring and will be used to demonstrate compliance with the NOx emissions standard. The exclusive firing of pipeline-quality natural gas minimizes emissions of sulfuric acid mist (SAM) and SO_2. Based on the most recent HAP emissions data available, the project does not trigger a 112(g) case-by-case MACT determination.

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

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

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

Mediation is not available in this proceeding.

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

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

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

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

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

Dept. of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southwest District Office
Air Resources
3804 Coconut Palm Drive
Tampa, FL 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Hillsborough County Environmental
Protection Commission
Air Management Division
1410 North 21 Street
Tampa, FL 33605
813/272-5530
Fax: 813/272-5605

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

3919 11/30/01

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

7000 2870 0000 7028 3109

OFFICIAL USE

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

Postmark Here

Sent To
Karen Sheffield
Street, Apt. No.; or PO Box No.
Port Sutton Road
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:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Ronald Toeltoh B. Date of Delivery 7-11-03

C. Signature
X Ronald Toeltoh ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

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

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

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 3109

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

UNITED STATES POSTAL SERVICE

TAMPA, FL 33

PM

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

RECEIVED
JAN 14 2002
BUREAU OF AIR REGULATION

01

Table 4-6A. RBLC VOC Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0128	ALABAMA POWER COMPANY - THEODORE COGEN	THEODORE	3/16/99	6/23/99	TURBINE, WITH DUCT BURNER	170.0 MW	0.016 LB/MMBTU	EFFICIENT COMBUSTION	BACT-PSD
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325.0 MMBTU/HR	8 LB/HR	NATURAL GAS AS PRIMARY FUEL	LAER
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, GAS, COMBINED CYCLE LM6000	421.4 MMBTU/H	1.1 LB/H	OXIDATION CATALYST	BACT
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, GAS, COMBINED CYCLE LM6000	421.4 MMBTU/H	1.1 LB/H	OXIDATION CATALYST	BACT
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, SIMPLE CYCLE LM6000 GAS	421.4 MMBTU/H	1.1 LB/H	OXIDATION CATALYST	BACT
CA-0813	SEPCO	RIO LINDA	10/5/94	8/31/99	TURBINE, GAS COMBINED CYCLE GE MODEL 7	920.0 MMBTU/H	3.7 LB/H	OXIDATION CATALYST	BACT
CA-0853	KERN FRONT LIMITED	BAKERSFIELD	11/4/86	8/5/99	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25.0 MW	3.12 LB/H	OXIDATION CATALYST. VOC IS SHOWN AS CH4.	BACT-OTHER
CA-0855	CROCKETT COGENERATION - C&H SUGAR	CROCKETT	10/5/93	4/19/99	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(FA)	240.0 MW	352.6 LB/D	ENGELHARD OXIDATION CATALYST	BACT-OTHER
CA-0858	BEAR MOUNTAIN LIMITED	BAKERSFIELD	8/19/94	9/28/99	TURBINE, GE, COGENERATION, 48 MW	48.0 MW	0.6 PPMVD @ 15% O2	OXIDATION CATALYST	BACT-OTHER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246.0 MMBTU/H	16.7 LB/H		OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350.0 MMBTU/H	26.7 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385.0 MMBTU/H EACH TURBIN	35.2 T/YR		OTHER
CO-0024	PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	5/1/96	5/19/98	COMBINED CYCLE TURBINES (2), NATURAL	471.0 MW	1.4 PPMVD, SMPL CY	GOOD COMBUSTION CONTROL PRACTICES.	BACT-PSD
CO-0039	FULTON COGENERATION ASSOC., L.P.	BRUSH	8/23/99	12/11/00	ELECTRIC GENERATION, TURBINES, NATURAL GAS	142.0 MW	3 PPMVD @ 15% O2	COMBUSTION CONTROLS	BACT-PSD
CT-0073	PRATT & WHITNEY, UTC	MIDDLETOWN	7/7/89	4/30/90	ENGINE, GAS TURBINE	238.0 MMBTU/H	0.014 LB/MMBTU		BACT-PSD
CT-0139	PDC EL PASO MILFORD LLC	MILFORD	4/16/99	6/17/99	TURBINE, COMBUSTION, ABB GT-24, #1	2.0 MMCF/H	3 LB/H NAT GAS	COMBUSTION CONTROLS	BACT
CT-0140	PDC EL PASO MILFORD LLC	MILFORD	4/16/99	6/17/99	TURBINE, COMBUSTION, ABB GT-24E,#2	2.0 MMCF/H	3 LB/H NAT GAS	COMBUSTION CONTROLS	BACT
FL-0042	ORLANDO UTILITIES COMMISSION	TITUSVILLE	9/1/88	5/14/93	TURBINE, 2 EA	35.0 MW	7 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400.0 MW	9 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	33394	3/24/95	TURBINE, GAS, 4 EACH	400.0 MW	1.6 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWER	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240.0 MW	1 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35.0 MW	7 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	10 PPMVD	GOOD COMBUSTION	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1,214.0 MMBTU/H	6 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1,510.0 MMBTU/H	7 PPMVW	GOOD COMBUSTION PRACTICES	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1,032.0 MMBTU/H, NAT GAS	0.003 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116.0 MW	6 PPMVD	COMPLETE COMBUSTION	BACT-PSD
GA-0069	TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	12/18/98	6/23/99	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.0 MW EA	0.03 LB/MMBTU	VOC EMISSION IS BECAUSE OF NATURAL GAS.	BACT-PSD
GA-0069	TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	12/18/98	6/23/99	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.0 MW EA	0.0055 LB/MMBTU	VOC EMISSION IS BECAUSE OF NO.2 FUEL OIL.	BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338.0 MM BTU/HR TURBINE	3.6 LB/HR COMBINED	COMBUSTION CONTROLS, FUEL SELECTION	BACT
LA-0118	OCCIDENTAL CHEMICAL CORPORATION	HAHNVILLE	3/19/99	3/19/01	GAS TURBINES (3 UNITS)	170.0 MW	3 LB/H	DLN COMBINATION WITH OTHER TECHNOLOGIES	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1,327.0 MMBTU/H	5.1 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH	BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528.0 MW TOTAL	0.4 PPM @ 15% O2		BACT-PSD
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175.0 MW	3 LB/H GAS		BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	7/13/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170.0 MW EACH	1 PPM	LOW NOX BURNER	BACT-PSD
MI-0245	SOUTHERN ENERGY, INC.	ZEELAND	3/16/00	8/22/00	COMBINED CYCLE TURBINE	9,000.0 GIGAJOULES	0.008 LB/MMBTU	PER CT. GOOD COMBUSTION PRACTICE	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1,313.0 MM BTU/HR	2 LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1,190.0 MMBTU/HR (EACH)	0.0046 LB/MMBTU	TURBINE DESIGN	OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617.0 MMBTU/HR (EACH)	4 PPMDV	TURBINE DESIGN	BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11,257.0 HP	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100.0 MW	0 SEE P2	GOOD COMBUSTION PRACTICES	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100.0 MW	0		BACT-PSD
NY-0036	ONEIDA COGENERATION FACILITY	ONEIDA	2/26/90	5/18/90	TURBINE, GE FRAME 6	417.0 MMBTU/H	0.013 LB/MMBTU	COMBUSTION CONTROL	OTHER
NY-0038	EMPIRE ENERGY - NIAGARA COGENERATION CO.	LOCKPORT	5/2/89	5/18/90	TURBINE, GR FRAME 6, 3 EA	416.0 MMBTU/H	0.012 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
NY-0039	FULTON COGENERATION ASSOCIATES	FULTON	1/29/90	5/18/90	TURBINE, GE LM5000, GAS FIRED	500.0 MMBTU/H	5 LB/H	COMBUSTION CONTROL	BACT-PSD
NY-0040	JMC SELKIRK, INC.	SELKIRK	11/21/89	5/18/90	TURBINE, GE FRAME 7, GAS FIRED	80.0 MW	7 PPM	COMBUSTION CONTROL	BACT-PSD
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123.0 MMBTU/HR (EACH)	0.0045 LB/MMBTU	OXIDATION CATALYST	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON CRT HSE	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5,500.0 HP (EACH)	0.1 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS	OTHER
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6 KW EACH	105 PPM @ 15% O2	OXIDATION CATALYST	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360.0 MMBTU/HR	4.4 LB/HR	GOOD COMBUSTION PRACTICES	BACT-OTHER
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	1/12/99	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153.0 MW	4 PPM @ 15% O2	OXIDATION CATALYST WHEN FIRING NO. 2 OIL	LAER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5.0 MW	25 PPMV@15%O2	GOOD COMBUSTION	BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461.0 MW	5 PPMDV	COMBUSTION CONTROLS.	BACT-PSD
RI-0008	PAWTUCKET POWER	PAWTUCKET	1/30/89	3/31/91	TURBINE/DUCT BURNER	533.0 MMBTU/H	19 PPM @ 15% O2, GAS		BACT-PSD
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1,360.0 MMBTU/H EACH	5 PPM @ 15% O2		BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	33450	5/31/92	TURBINE, GAS, 2	49.0 MMBTU/H	0.016 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-OTHER
RI-0018	TIVERTON POWER ASSOCIATES	TIVERTON	2/13/98	2/8/99	COMBUSTION TURBINE, NATURAL GAS	265.0 MW	2 PPM @ 15% O2	GOOD COMBUSTION	BACT-PSD
SC-0031	BMW MANUFACTURING CORPORATION	GREER	1/7/94	8/12/96	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5 MM BTU/HR TURBINES	77.86 LBS/DAY		LAER
TN-0077	TN VALLEY AUTHORITY LAGOON CREEK COMBUS TURB	BROWNSVILLE	4/26/00	8/16/00	COMBUSTION TURBINE	194,400.0 MMBTU/H	1.4 PPM @ 15% O2	ANNUAL PRODUCTION LIMITS	BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	38 TPY	INTERNAL COMBUSTION CONTROLS	BACT
VA-0163	VIRGINIA POWER		9/7/89	4/30/90	TURBINE, GAS	1,308.0 MMBTU/H	2 LB/H/UNIT NAT GAS FI		BACT-PSD
VA-0177	DOSWELL LIMITED PARTNERSHIP		5/4/90	3/24/95	TURBINE, COMBUSTION	1,261.0 MMBTU/H	4.4 LB/H	COMBUSTOR DESIGN & OPERATION, GAS	OTHER
VA-0180	COMMONWEALTH GAS PIPELINE CORPORATION	GOOCHLAND	9/30/90	3/24/95	TURBINES, GAS FIRED, SINGLE CYCLE, 5	14.5 MMBTU/H EACH	0	EQUIPMENT DESIGN & OPERATION	BACT-PSD
VA-0184	BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	CHESTERFIELD	3/3/92	5/7/97	TURBINE, COMBUSTION	1,175.0 MMBTU/H NAT. GAS	2.3 LB/H/UNIT	FURNACE DESIGN	BACT-PSD
VA-0238	COMMONWEALTH CHESAPEAKE CORPORATION	NEW CHURCH	5/21/96	7/21/97	3 COMBUSTION TURBINES (OIL-FIRED)	6,000.0 HRS/YR	38.9 TPY	GOOD COMBUSTION OPERATING PRACTICES	BACT/NSPS

Source: RBLC 2001.

MAXIMUM	105.0 PPM @ 15% O2
MINIMUM	0.4 PPM @ 15% O2
MEDIAN	5.0 PPM @ 15% O2

Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

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

Expiration Date: July 5, 2002
Permit No.: 0570040-012-AC
Facility ID No.: 0570040
SIC No.: 49, 4911
Project: Gannon Station - Unit Nos. 1, 2, & 4 WDF Modification

STATEMENT OF BASIS: This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-204, 62-210, 62-212, 62-213, 62-296, 62-297, and Chapter 62-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans and other documents, attached hereto or on file with the Florida Department of Environmental Protection:

This permit is for the modification of the F. J. Gannon Station Unit Nos. 1, 2, and 4 steam generator operating limitations to allow for the firing of a coal and wood-derived fuel (WDF) blend. WDF can be composed of Paper Pellets, Yard Trash, and Wood/Wood Chips, as defined in this permit.

Effective Date: (clerk date)

Howard L. Rhodes, Director
Division of Air Resources Management

HLR/sms

Subsection A. Summary of Emissions Unit ID Nos. and Brief Descriptions.

E.U. ID No.	Brief Description
-001	Unit No. 1-Fossil Fuel-Fired Steam Generator
-002	Unit No. 2-Fossil Fuel-Fired Steam Generator
-004	Unit No. 4-Fossil Fuel-Fired Steam Generator

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test submittals, applications, etc.

Subsection B. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

These documents are on file with permitting authority:
AC permit application received August 28, 2000.
Additional information requested September 26, 2000.
TECO response received November 27, 2000.
Additional information requested December 27, 2000.
TECO response received March 21, 2001.

1. A part of this permit is the attached 15 General Conditions. [Rule 62-4.160, F.A.C.]

2. Issuance of this permit does not relieve the permittee from complying with applicable emission limiting standards or other requirements of Chapters 62-204, 62-210, 62-212, 62-213, 62-296 and 62-297, or any other requirements under federal, state or local law.
[Rule 62-210.300, F.A.C.]

Operation Limitations - Fuels

3. This permit allows Unit Nos. 1, 2, and 4 to be fired on a coal/wood-derived fuel (WDF) blend with the following restrictions:

A. The maximum amount of WDF fired in a boiler shall not exceed 10% of the fuel fired in a boiler on a weight basis. The total quantity of WDF fired in Unit Nos. 1, 2, 3, and 4 shall not exceed 56,940 tons per consecutive 12-month period *(56,940 TPY is the calculated weight basis from Unit No. 3, allowed by Permit No. 0570040-012-AC).*
(* *Note: See C. below for additional restrictions.*)

B. WDF shall be defined only as material falling under one of the following type categories (* *Note: See C. below for additional restrictions*):

i. Paper Pellets - Pellets consisting of paper, cardboard and polymer-impregnated or coated paper, such as disposable drinking cups, paper plates, etc., It shall include no materials coated or treated with hazardous substances including, but not limited to, tar, asphalt, and coatings containing heavy metals. Pellets shall be free of hazardous substances and as free as practicable of metal, hard plastics, textiles, and food products.

ii. Yard Trash - As defined in Rule 62-701.200 (90), F.A.C., and shall contain only vegetative material resulting from landscaping maintenance or land clearing operations and includes materials such as trees and shrub trimmings, grass clippings, palm fronds, trees and tree stumps.

iii. Wood/Wood Chips - Derived from clean wood lumber, pallets, construction debris free of listed hazardous substances including, but not limited to, pentachlorophenol, creosote, tar, asphalt, and paint containing heavy metals.

C. Based upon the operating conditions during the April 18 and 19, 2000, WDF test burn for Unit No.3, the following additional WDF usage restrictions apply until additional compliance stack testing is done during firing of different WDF blend ratios and WDF types.

i. WDF is limited to a maximum of 4.0% of the fuel fired in a unit on a weight basis.

ii. WDF is limited to paper pellets only.

In order to increase the WDF blend ratio above the level in C. i. (but never to exceed 10% WDF), or allow for the blending of Yard Trash and Wood/Wood Chips as part of the WDF, then additional testing shall be conducted on the applicable unit. To increase the blend % for WDF consisting of paper pellets only, PM and VE testing only will be required. Successful testing showing compliance with the operation permit limitations at a higher blend ratio will allow future operation up to that level + 10% (not to exceed 10% WDF by weight). Successful testing (i.e. testing showing compliance with the permit limitations and demonstrating no increase in emissions due to the inclusion of the additional types of WDF) while firing Yard Trash and Wood/Wood Chips will allow for subsequent use of those categories of WDF as part of the coal/WDF blend. The permittee shall notify the Air Compliance Section of the Southwest District Office of the Department and the Air Management Division of the Environmental Protection Commission of Hillsborough County (EPC), at least 15 days prior to the date on which each formal compliance test is to begin of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted. The test notification shall include a proposed test protocol which, upon agreement by the Department, will establish the testing to be done and the conditions under which the test will be conducted and evaluated. A copy of the test report shall be submitted to the Air Management Division of the EPC and the Air Compliance Section of the Southwest District Office of the Department within 45 days after the test is completed.

Testing Note: *As it deems appropriate and applicable, the Department may take into account the results of any WDF blend testing conducted on a unit in approving changes to WDF types and blend ratios in lieu of additional testing.*

D. Paper pellets fired in this unit shall be produced using a waste separation process as described or similar to that described as the "typical waste separation process for Paper Pellets" submitted as Attachment D to the application for Permit No. 0570040-011-AC, including separation of large items, hand sorting, metal extraction/separation, air classification, organic material screening, and large film plastic removal; or equivalent waste separation processing methods (i.e. methods that are designed to result in a target level of approximately 5% or less non-paper materials in the final waste stream). Each time that the permittee receives material from a new paper pellet supplier, or there is a significant change in the waste separation process of a prior supplier, the permittee shall submit a detailed description of the waste separation process used by that supplier (or changes to a previously submitted supplier's process) to the Air Management Division of the Environmental Protection Commission of Hillsborough. The Department reserves the right to request additional information, require additional testing of, or disapprove use of paper pellets from this supplier if it has good reason to believe that this waste separation process will not result in material that meets the above definition of Paper Pellets.

[Rules 62-4.070(3), 62-297.310(7)(a)9, and 62-297.310(8), F.A.C., permit application dated August 1998, and Department test burn authorization letter of March 18, 1997]

3.1. The firing of coal and WDF blend in these units is prohibited after December 31, 2004.
[Consent Decree (U.S. vs. TECO) dated February 29, 2000]

Additional Recordkeeping Requirements

4. In order to document compliance with Specific Condition No. 3, the permittee shall maintain daily records for each unit of the quantity (tons) of WDF fired, with a statement as to the type(s) of WDF included (i.e. Paper Pellets, Yard Trash and/or Wood/Wood Chips), and the coal/WDF blend ratio (on a weight basis). The permittee shall also keep records, on a monthly basis of the estimated total of WDF fired by type (i.e. Paper Pellets, Yard Trash and/or Wood/Wood Chips). This monthly record shall also include a statement identifying the suppliers of the paper pellets used that month. These records shall be recorded in a permanent form suitable for inspection by the Department upon request, and shall be retained for at least a five (5) year period.
[Rule 62-4.070(3), F.A.C.]

Additional Compliance Testing Requirements

5. Future annual particulate matter and visible emissions testing shall be conducted while firing coal/WDF blend at 90-100% of the maximum permitted WDF blend ratio (or the maximum WDF blend ration for which the permittee wants the unit to be permitted for, not to exceed 10% WDF). This requirement may be waived (and testing done on 100% coal) if coal/WDF blend has been fired for less than 400 hours in the previous 12 month period and it is anticipated that it will not be used for more than 400 hours in the next 12 month period. The test reports shall include a statement and documentation of the coal/WDF blend ratio (weight basis) in use during the test, including a statement as to the types of WDF (i.e. Paper Pellets, Yard Trash and/or Wood/Wood Chips) included in the WDF material fired.
[Rules 62-4.070(3), and 62-297.310(20) and (8), F.A.C.]

Title V Permit Revision

6. Within 180 days of completion of testing of each unit, the permittee shall submit a Title V operation permit revision application to include the terms of this construction permit in the Title V permit for the F. J. Gannon Station.
[Rule 62-213.420, F.A.C.]

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Tampa Electric Company (TECO)
F. J. Gannon Station
Facility ID No.: 0570040
Hillsborough County

Air Construction (Modification) Permit
Permit No.: 0570040-012-AC

Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation

June 11, 2001

1. GENERAL INFORMATION

1.1 APPLICANT NAME AND ADDRESS

Authorized Representative: Ms. Karen A. Sheffield, P.E.
General Manager

F. J. Gannon Station
Tampa Electric Company
P. O. Box 111
Tampa, Florida 33601-0111

1.2 REVIEW AND PROCESS SCHEDULE

August 28, 2000	Received permit application.
September 26, 2000	Additional information requested.
November 27, 2000	TECO response received.
December 27, 2000	Additional information requested.
March 21, 2001	TECO response received; application deemed complete.

2. FACILITY INFORMATION

This facility is located at Port Sutton Road, Tampa, Hillsborough; UTM Coordinates: Zone 17, 360.1 km East and 3087.5 km North; Latitude: 28° 02' 31" North and Longitude: 82° 25' 31" West.

The SIC code is:

Industry Group No.	49	Electric, Gas and Sanitary Services

The F. J. Gannon station consists of six steam boilers (Units 1 through 6); six steam turbines; one simple-cycle combustion turbine; a once-through cooling water system; solid fuels, fluxing material, fly ash, slag, and storage/handling facilities; fuel storage tanks; and ancillary support equipment. The nominal output is 1317 megawatts (MW). The facility utilizes coal as its primary fuel for Units 1-6. The combustion turbine is allowed to burn new No. 2 fuel oil, with a maximum sulfur content of 0.5%, by weight.

The requested modification is to allow TECO the flexibility to burn Wood Derived Fuel (WDF)/coal blends in Units 1, 2, and 4 in accordance with the same conditions specified by Permit No. 0570040-011-AC. The maximum WDF allowed to be burned at the station does not change.

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

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). This facility is a major source of hazardous air pollutants (HAPs).

3. PERMIT DESCRIPTION

The applicant requests approval to burn Wood Derived Fuel (WDF)/coal blends in Units 1, 2, and 4.

Unit No. 3 is currently permitted to burn Wood Derived Fuel (WDF). Unit No. 3 began commercial operation in August 1960.

This Permit addresses emissions units –001, 002, and –004 (Unit Nos. 1, 2 and 4 respectively).

4. PERMIT EMISSIONS & RULE APPLICABILITY

A comparison of past actual annual emissions to future actual representative annual emissions for Units 1, 2, and 4 was provided by Thomas W. Davis, P.E., ECT, on November 27, 2000. When firing WDF, emissions of SO_2 and NO_x decrease. A brief summary for each unit is shown below.

Unit No. 1

Pollutant	Combustion of coal only	Combustion of coal with WDF	Emission Rate Change
PM	84.4 TPY	84.4 TPY	0 TPY
PM10	84.4 TPY	84.4 TPY	0 TPY
H_2SO_4	20.8 TPY	20.8 TPY	0 TPY
SO_2	4,363.9 TPY	4,327.3 TPY	-36.6 TPY
NO_X	2,158.0 TPY	2,011.7 TPY	-146.3 TPY
VOC	16.2 TPY	16.2 TPY	0 TPY
CO	830.0 TPY	830.0 TPY	0 TPY

Unit No. 2

Pollutant	Combustion of coal only	Combustion of coal with WDF	Emission Rate Change
PM	80.3 TPY	80.3 TPY	0 TPY
PM10	80.3 TPY	80.3 TPY	0 TPY
H_2SO_4	19.8 TPY	19.8 TPY	0 TPY
SO_2	4151.0 TPY	4,116.2 TPY	-34.8 TPY
NO_X	2,052.8 TPY	1,913.6 TPY	-139.2 TPY
VOC	15.5 TPY	15.5 TPY	0 TPY
CO	789.5 TPY	789.5 TPY	0 TPY

Unit No. 4

Pollutant	Combustion of coal only	Combustion of coal with WDF	Emission Rate Change
PM	134.5 TPY	134.5 TPY	0 TPY
PM10	134.5 TPY	134.5 TPY	0 TPY
H_2SO_4	33.1 TPY	33.1 TPY	0 TPY
SO_2	6,954.4 TPY	6,896.1 TPY	-58.3 TPY
NO_X	3,439.1 TPY	3,205.9 TPY	-233.2 TPY
VOC	25.9 TPY	25.9 TPY	0 TPY
CO	1,322.7 TPY	1,322.7 TPY	0 TPY

Tests were conducted on unit No. 3 while firing a blend of coal and 4% WDF on April 18 & 19, 2000. A summary of the test results is shown below. Air pollutant emissions *decreased* for SO_2 and NO_x.

Pollutant	Combustion of coal only	Combustion of coal with 4% WDF	Emission Rate Change
PM - Sootblowing	0.03 lb/MMBTU	0.03 lb/MMBTU	0 lb/MMBTU
H_2SO_4	0.003 lb/MMBTU	0.003 lb/MMBTU	0 lb/MMBTU
SO_2[1]	1.551 lb/MMBTU	1.538 lb/MMBTU	-0.013 lb/MMBTU
NO_X[1]	0.767 lb/MMBTU	0.715 lb/MMBTU	-0.052 lb/MMBTU
VOC	0 lb/MMBTU	0 lb/MMBTU	0 lb/MMBTU
VE	0	0	0

All data based on stack test unless otherwise noted.

[1] CEM data.

Because this Permit requires a modification, an AC permit is required and the public notice requirements for AC permits are applicable.

The proposed Permit is otherwise subject to preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). Allowable excess emissions will not change as a result of this Permit.

The facility is located in an Hillsborough County designated "attainment" for all the criteria pollutants (Rule 62-204.360, F.A.C.).

The emission units affected by this permit shall comply with all applicable provisions of the Florida Administrative Code.

5. AIR POLLUTION CONTROL TECHNIQUES

No emission limits or compliance requirements will change as a result of this Permit.

6. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant and other available information, the Department has made a preliminary determination that the proposed Permit will comply with all applicable state and federal air pollution regulations. The Department will issue a draft AC permit to the applicant that provides for the above changes.

Scott M. Sheplak, P.E.
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
850/921-9532

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 12, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Karen A. Sheffield, P.E.
General Manager
Tampa Electric Company
P. O. Box 111
Tampa, Florida 33601-0111

Re: Permit No.: 0570040-012-AC
F. J. Gannon Station Unit Nos. 1, 2, & 4 WDF Modification

Dear Ms. Sheffield:

Enclosed is one copy of the draft air construction permit for the modification of the F. J. Gannon Station Unit Nos. 1, 2, and 4 steam generator operating limitations to allow the firing of a coal and wood-derived fuel (WDF) blend. The F. J. Gannon Station is located at Port Sutton Road, Tampa, Hillsborough County. The Department's Intent to Issue Air Construction Permit with Public Notice of Intent to Issue Air Construction Permit, and Technical Evaluation and Preliminary Determination, are also included.

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

Please submit any written comments you wish to have considered concerning the Department's proposed action to Scott M. Sheplak, P.E., Administrator, at the above letterhead address. If you have any questions, please contact him at 850/921-9532.

Sincerely,

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

CHF/sms

Enclosures

In the Matter of an
Application for Permit by:
Tampa Electric Company
P. O. Box 111
Tampa, Florida 33601-0111
/

Permit No.: 0570040-012-AC
F. J. Gannon Station
Hillsborough County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of draft permit attached) for the proposed project, detailed in the application specified above and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, Tampa Electric Company, applied on August 28, 2000, to the permitting authority for a modification of the F. J. Gannon Station Unit Nos. 1, 2, and 4 steam generator operating limitations to allow for the firing of a coal and wood-derived fuel (WDF) blend. The F. J. Gannon Station is located at Port Sutton Road, Tampa, Hillsborough County

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required for the modification.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emissions units will not adversely impact air quality, and the emissions units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

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

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

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

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

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

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

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

Mediation is not available in this proceeding.

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the draft permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6/14/01 to the person(s) listed:

Karen Sheffield, P.E., TECO *
Thomas W. Davis, P.E., ECT
Bill Thomas, P.E., SWD
Jerry Campbell, P.E., EPCHC

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) 6/14/01 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Permit No.: 0570040-012-AC
F. J. Gannon Station
Hillsborough County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Tampa Electric Company, for the modification of the F. J. Gannon Station Unit Nos. 1, 2, and 4 steam generator operating limitations to allow for the firing of a coal and wood-derived fuel (WDF) blend. The F. J. Gannon Station is located at Port Sutton Road, Tampa, Hillsborough County.

A Best Available Control Technology (BACT) determination was not required pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD). The applicant's mailing address is: Tampa Electric Company, P. O. Box 111, Tampa, Florida 33601-0111.

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

The Department will accept written comments concerning the proposed permit issuance action for a period of 14 (fourteen) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

Dept. of Environmental Protection
Bureau of Air Regulation
Suite 4, 111 S. Magnolia Drive
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

The complete project file includes the application, technical evaluations, Draft permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, Title V Section, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:
Tampa Electric Company
F.J. Gannon Station

Permit No.: 0570040-012-AC
Facility ID No.: 0570040

Project type: Air Construction - Unit Nos. 1, 2, & 4 WDF Modification

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

Scott M. Sheplak 06/19/01

Scott M. Sheplak, P.E.   Date
Registration Number: 48866

Permitting Authority:
Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/921-9532
Fax: 850/922-6979

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Karen A. Sheffield, P.E.
General Manager
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*)

B. Date of Delivery 6-18-01

C. Signature

X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
XX 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 0600 0021 2825 4771

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 0600 0021 2825 4771

Article Sent To:
Ms. Karen A. Sheffield, P.E.

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

Name (Please Print Clearly) (to be completed by mailer)
Ms. Karen A. Sheffield, P.E.
Street, Apt. No.; or PO Box No.
P.O. Box 111
City, State, ZIP+4
Tampa, Florida 33601-0111

PS Form 3800, July 1999 See Reverse for Instructions

U.S. Postal Service

CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

7000 0600 0021 2825 4771

Article Sent To:

Ms. Karen A. Sheffield, P.E.

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

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Ms. Karen A. Sheffield, P.E.
Street, Apt. No.; or PO Box No.
P.O. Box 111
City, State, ZIP+4
Tampa, Florida 33601-0111

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Ms. Karen A. Sheffield, P.E.
General Manager
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 6-18-01

C. Signature

X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
XX 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 0600 0021 2825 4771

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

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF AIR RESOURCES MANAGEMENT
BUREAU OF AIR REGULATION - TITLE V
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

MS 5505

RECEIVED
JUN 20 2001
BUREAU OF AIR REGULATION


BAYSIDE UNITS 3 & 4
AIR DISPERSION
MODELING FILES
ECT No. 991060 -0100-1100
JUNE, 2001