STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Walter P. Bussells, Chief Executive Officer
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202-3139

DEP File No. 0310485-001-AC, PSD-FL-267
Brandy Branch Facility
Duval County

Enclosed is Final Permit Number 0310485-001-AC. This permit authorizes Jacksonville Electric Authority to construct the Brandy Branch facility. 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 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

C. H. Fancy
C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10-14-99 to the person(s) listed:

Walter P. Bussells, JEA *
N. Bert Gianazza, P.E., JEA
Gregg Worley, EPA
John Bunyak, NPS
Chris Kirts, NED
James L. Manning, P.E. RESD
Anthony L. Compaan, Black & Veatch

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.

Kori Joken 10-14-99
(Clerk) (Date)

Z 031 391 960

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PS Form **3800**, April 1995

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Walter Bussells
Jacksonville Electric A.
21 W. Church St.
Jacksonville, Fl
32202-3139

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FINAL DETERMINATION

JEA
Brandy Branch/Baldwin City
DEP File No.0310485, PSD-FL-267

The Department distributed a public notice package on August 12, 1999 to allow the applicant to construct a new plant known as the Brandy Branch Facility located at Baldwin City, Duval County. The Public Notice of Intent to Issue was published in The Florida Times-Union on August 23, 1999.

COMMENTS/CHANGES

Comments were received from EPA by letter and facsimile correspondence dated September 10, 1999.

Comments were received from the Fish and Wildlife Service by letter dated August 30, 1999.

Comments were received from the applicant by electronic correspondences dated August 27 and September 24, 1999. Additionally, the Department received comments from the applicant requesting that the wording on the Public Notice be revised to reflect a maximum number of operating hours of 4750 of which 750 could be on oil. The Department agreed to the Public Notice change and will address the substantive issue herein.

EPA and the applicant commented on the Technical Evaluation and Preliminary Determination (TEPD), the BACT and the DRAFT Permit. The comments related to the BACT and permit are summarized below and the Department's responses are included following each comment. Comments related to the TEPD are noted and maintained in the file.

The Fish and Wildlife Service as well as the EPA commented on the need for CALPUFF modeling for visibility and regional haze in the (Class I) Okefenokee area. The applicant submitted this modeling on September 10, 1999 and (as indicated by FWS) the shutting down of the applicant's Southside Station along with the permitting of this new facility will cause a net benefit to visibility. A cumulative analysis, modeling all increment-consuming sources in the area, predicted SO_2 exceedances, which were not significantly contributed to by this facility. FDEP will investigate the matter to determine which sources are contributing significantly to the exceedances and develop possible remedies for further consideration..

DRAFT Permit Administrative Requirements:

The applicant requested that the requirements listed as Conditions 6. and 7. ("Expiration" and "BACT Determination") be removed due to the inapplicability of 40 CFR 52.21 in the State of Florida.

RESPONSE: These conditions will remain, with changes to the referenced citations associated with these conditions.

DRAFT Permit Specific Conditions:

1. *Specific Condition 4*: The applicant requested that the permit reflect the applicant's ability to install (optional) evaporative inlet cooling.

   RESPONSE: The requested change will be accommodated, as this option was referenced in the Technical evaluation.

2. *Specific Condition 7*: The applicant requested that parenthesis be placed around the words "No. 2 or superior grade of distillate oil".

   RESPONSE: The requested change will not be accommodated due to the possible inference that the adjective "superior" applies only to the grade of oil (No. 2) and not the sulfur content.

3. *Specific Condition 8*: The applicant requested that a permitting note be placed at the end of the condition, clarifying the Department's position on the purpose of heat input values.

RESPONSE: The following language is added to the end of the condition, as has been done in other permitting actions: {Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 95-100 percent of the emissions unit's rated capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability......}

4. *Specific Condition 13*: The applicant requested that the condition be reworded to clearly indicate total hours of permitted use and to be consistent with all modeling. Additionally, the EPA indicated a lack of clarity in hours of operation per combustion turbine and recommended that the use of the words "a calendar year" be replaced so as to be consistent with other permit conditions.

RESPONSE: The permit condition is reworded as follows: 13. Maximum allowable hours: Each stationary gas turbine shall only operate up to 4750 hours during any consecutive twelve month period, of which 750 hours of operation per combustion turbine may be while firing oil. Additionally, each turbine shall be limited to 16 hours per day of oil firing. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

5. *Specific Conditions 14 and 15*: The applicant requested that these conditions be deleted. The EPA commented that limits should be on an individual combustion turbine basis. These conditions had required facility-wide fuel usage monitoring and reporting on a monthly basis.

RESPONSE: The aforementioned permit conditions are deleted as the newly worded Specific Condition 13 dictates a precise (and different) method of compliance per combustion turbine.

6. *Specific Condition 17*: The applicant requested that this condition be deleted. The EPA commented that the related NOx limits should be lower and have shorter compliance times.

RESPONSE: This condition requires that the units be constructed so as to be easily capable of accommodating an SCR should one be required in order to meet the NOx limits. Given that the applicant initially requested a NOx limit of 12 ppm and that the Department has imposed a more stringent limit of 10.5 ppm, this condition will not be deleted.

7. *Specific Condition 20*: The applicant requested language changes to accurately reflect the purpose and basis of the chart, noting that a BACT analysis was not required for VOC.

RESPONSE: A note will be added below the chart indicating that the VOC limit was not determined by BACT.

8. *Specific Condition 21*: The EPA suggested that the limits imposed by the second "bullet" be more stringent. The EPA additionally commented on the applicability of SCR (as discussed in the BACT) questioning several of the applicant's assumptions (through its comments 4., 5. and 6.). The applicant requested that the condition imposed by the fourth "bullet" (requirement to evaluate lower NOx emissions while firing oil) be deleted or reworded.

RESPONSE: The limits imposed by the second bullet are related to NOx emissions while firing natural gas. The Department appreciates the concerns raised by the EPA, but believes that extenuating circumstances are involved. Namely, these are:

1) The applicant has proposed to shutdown an existing facility (Southside) in an effort to offset most air emission-related issues. The result should yield a net reduction of regulated pollutants emitted on an annual basis.

2) By imposing a limit of 10.5 ppm (versus 12 ppm as proposed by the applicant), the Department estimates that the net NOx emissions of the combined actions noted above are approximately zero TPY. Further mandated NOx reductions may be viewed as punitive.

3) In order to accommodate the applicant's concern about their ability to routinely achieve this lower imposed limit as well as the applicant's action noted in 1) above, the Department believes that a compliance method which is more flexible than is normally required can be allowed.

Therefore, the limits imposed by the second bullet will not be changed. However, the BACT will incorporate these extenuating circumstances as a part of the Department's justification. Concerning the applicant's request on the fourth "bullet", the wording will be revised in a fashion similar to that proposed by the applicant.

9. *Specific Condition 22*: The applicant requested that EPA method 10 be clearly indicated as the method of compliance for both the concentration and lb/hr limit of CO emissions. The applicant additionally noted that vendor guarantees for CO have only been obtained at the 15 ppm level, versus the 12 ppm level identified in the draft BACT. The applicant indicated that reasonable assurance for a 12 ppm emission rate cannot be provided and requested the ability to evaluate a lower limit (via testing and analysis) after the initial (15 ppm) acceptance test and subsequent testing is completed.

RESPONSE: Language similar to that proposed by the applicant for EPA Method 10 will be added. Concerning the CO limit, permit language will be included (similar to what is shown in Specific Condition 21 (fourth bullet)) including an "initial" 15 ppm limit with a requirement to submit an evaluation to FDEP concerning a lower limitation.

10. *Specific Condition 24*: The EPA requested that the permit conditions should list the corresponding particulate matter emissions rate limit even though opacity will be used as the method of compliance. Additionally, the EPA questioned the allowance of 20% opacity during startup and shutdown, noting that FDEP routinely permits combustion turbines without this "automatic" allowance.

RESPONSE: The Department agrees with EPA and will revise this condition accordingly.

11. *Specific Condition 26*: The applicant requested that an assumed typographical error be corrected in this condition.

RESPONSE: The typographical error will be corrected.

12. *Specific Condition 27*: The applicant requested that compliance-related notifications should be made to RESD and not duplicated to the Department. Additionally, the applicant requested that the condition be revised to accurately reflect Rule 62-210.700(6), F.A.C.

RESPONSE: Administrative Requirement number 13 as well as Specific Conditions 6, 27, 35, 37 and 41 will be re-worded to accurately reflect the Department's intent regarding compliance-related notifications. Specific Condition 27 will be revised to accurately reflect Rule 62-210.700(6), F.A.C.

13. *Specific Condition 29*: The applicant requested a revision to this condition clarifying the Department's intent concerning initial testing on oil as well as shake-down testing.

RESPONSE: Language similar to that proposed by the applicant will be added for initial testing on oil. However, the condition will not be revised in such a manner to allow routine or repetitive shakedown periods after the initial 100 days of operation.

14. *Specific Condition 30*: The applicant requested a revision to this condition eliminating reference to SCR controls and clarifying the Department's intent concerning 3-hr and 24-hr averaging times for NOx compliance.

RESPONSE: The Department will clarify its intent. However, the Department intends to allow for the possibility of SCR controls to be installed as indicated in prior discussion above.

15. *Specific Condition 31*: The applicant requested a revision to this condition so as to have similar language to other permits regarding the sulfur content of natural gas.

RESPONSE: The Department will modify the language so as to replicate other permits.

16. *Specific Condition 33*: The applicant requested a revision to this condition so as to eliminate the reference to the VOC limit having been determined by BACT.

RESPONSE: The Department will eliminate this reference in this condition.

17. *Specific Condition 40*: The applicant requested a revision to this condition to be consistent with its request in item 4. above.

RESPONSE: The Department will revise this condition so as to provide a means of compliance with the newly worded permit conditions (concerning hours of operation per CT).

18. *Specific Condition 41*: The applicant requested that this condition be revised so as to eliminate the last sentence or (at a minimum) to eliminate the words "and fuel switching".

RESPONSE: The Department will eliminate the words "and fuel switching".

19. *Specific Condition 43*: The applicant requested that this condition be revised so as to be consistent with other similar permitting actions.

RESPONSE: The Department will comply with this request.

20. *Specific Condition 45*: The applicant requested that this condition be revised for clarity so as to indicate when an Acid Rain permit should be applied for.

RESPONSE: The Department will comply with this request.

CONCLUSION

The final action of the Department is to issue the permit with the changes described above.

PERMITTEE:

Jacksonville Electric Authority
Brandy Branch Facility
21 West Church Street
Jacksonville, Florida 32202-3139
Authorized Representative:

Walter P. Bussells, Chief Executive Officer

File No.	PSD-FL-267
FID No.	0310485
SIC No.	4911
Expires:	12/31/02

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators and three 90-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability. They are designated by JEA as Combustion Turbine Generators 1, 2 and 3 and by the Department as ARMS Emissions Units 001, 002 and 003.

The project will be located approximately 1 mile N.E. of Baldwin City, Duval County. UTM coordinates are: Zone 17; 408.81 km E; 3354.38 km N.

STATEMENT OF BASIS:

This PSD 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 40CFR51.166. The above named permittee is authorized to modify the facility 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 of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

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

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with three 90-foot stacks and three fuel oil storage tanks.

Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS Emissions Unit	System	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
005	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
006	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

The 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 (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 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). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 08/23/99 Notice of Intent published in The Florida Times-Union
- 08/12/99 Distributed Intent to Issue Permit
- 08/06/99 Application deemed complete
- 05/18/99 Received Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on May 18, 1999
- Department letters dated May 26 and July 21, 1999
- Comments from the Fish and Wildlife Service dated July 20, August 12 and August 30, 1999
- Letter from JEA dated June 21, 1999
- Letter (e-mail) from JEA dated August 4, 1999 and related submittals
- Department's Intent to Issue and Public Notice Package dated August 12, 1999
- Letters (e-mail) from JEA dated August 27 and September 24, 1999
- Letter (facsimile) from EPA dated September 10, 1999
- Letter from Golder Associates Inc. dated September 10, 1999 and regional haze analysis
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: 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 (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Northeast District office, 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256 and phone number 904/448-4300; additionally, such documents shall be submitted to RESD, Suite 225, 117 W. Duval St., Jacksonville, Florida 32202 and phone number 904/630-3484.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: 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. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [62-4.070(4), 62-4.210(2)&(3), 62-210.300(1)(a)].
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 51.166(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation (e.g. conversion to combined-

cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166, Rule 62-4.070 F.A.C.]

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Northeast District office as well as RESD. [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Northeast District office as well as RESD by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit [Rule 62-4.080, F.A.C.]

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to RESD. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

14. Retirement of existing facility: In accordance with JEA's analyses of regional haze in the nearby Class I areas, the Brandy Branch facility may cause or contribute to haze values greater than 5%. In order to mitigate this possibility, JEA will limit the operation of the combustion turbines permitted herein to a maximum of 16 hours per day of oil operation. Additionally, so as to cause a net benefit to the nearby Class I areas, JEA shall retire the existing Southside Facility (AIRS ID 0310046) located at 801 Colorado Avenue, Jacksonville, Florida upon JEA's application for a Title V permit for the Brandy Branch facility (including certification that the facility is in compliance with applicable requirements and permit conditions). JEA shall concurrently submit a letter from the designated representative of the Southside facility certifying that the facility has been shutdown and that related permits are being surrendered. This shall occur on or before October 31, 2002.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.
2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

- 40CFR60.7, Notification and Recordkeeping
- 40CFR60.8, Performance Tests
- 40CFR60.11, Compliance with Standards and Maintenance Requirements
- 40CFR60.12, Circumvention
- 40CFR60.13, Monitoring Requirements
- 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines (with optional evaporative inlet cooling) shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]
5. ARMS Emission Units 004-006, Fuel Storage, consisting of three 1 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]
6. All notifications and reports required by the above specific conditions shall be submitted to RESD.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] {Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,623 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,822 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. {Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in this permit requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods (including but not limited to) fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the operator to calculate average hourly heat input during the test.} [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. 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.]

10. 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 owner or operator shall notify the DEP Northeast District office and RESD as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the 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 and the regulations. [Rule 62-4.130, F.A.C.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

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

13. Maximum allowable hours: Each stationary gas turbine shall only operate up to 4750 hours during any consecutive twelve month period, of which 750 hours of operation per combustion turbine may be while firing oil. Additionally, each turbine shall be limited to 16 hours per day of oil firing. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

14. [DELETED]

15. [DELETED]

Control Technology

16. Dry Low NO_X (DLN) combustors shall be installed on each stationary combustion turbine to control NO_X emissions while firing natural gas. [BACT, Rule 62-4.070, F.A.C.]

17. The permittee shall design each stationary combustion turbine, ducting, and stack(s) so as to not preclude installation of SCR equipment and/or oxidation catalyst in the event of a failure to achieve the NO_X limits given in Specific Condition No. 20 and 21 or the carbon monoxide (CO) limits given in Specific Condition 22. [Rule 62-4.070, F.A.C.]

18. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070, 62-212.400, F.A.C.]

19. Consistent with best operation and maintenance practices, the DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rules 62-4.070, 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

20. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15% O_2 on a dry basis. [Rule 62-212.400, F.A.C.]

Operational Mode (Fuel)	NO_X (15%O2)	CO	VOC***	PM/Visibility (% Opacity)	SO_2/SAM	*Technology and Comments*
Natural Gas	10.5 ppm	15** ppm	2 ppm	10	2 grain S per 100 CF	Dry Low NOx Burners. Clean fuels, good combustion
Fuel Oil	42 ppm*	20 ppm	3.5 ppm	10	0.05% sulfur oil	Water Injection. Units limited to 750 hrs equivalent full load oil operation (per CT) annually. Clean fuels, good combustion

NOTES: * See Condition 21. ** See Condition 22. *** The VOC limit imposed herein was not determined by BACT.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

21. Nitrogen Oxides (NO_X) Emissions:

- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- While firing Natural Gas: The emission rate of NO_X in the exhaust gas shall not exceed 69.3 lb/hr (at ISO conditions) on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 10.5 ppm @15% O_2 to be demonstrated by annual stack test nor 9 ppm @15% O_2 to be demonstrated by the initial "new and clean" GE performance stack test. Note: Basis for lb/hr limit is 10.5 ppm @ 15% O_2, full load. [Rule 62-212.400, F.A.C.]
- While firing Fuel oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 42 ppm @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- After combusting fuel oil for at least 400 hours on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest NO_X emission rate that can consistently be achieved when firing distillate oil. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the NO_X emission rate based upon this report. [BACT determination]

22. Carbon Monoxide (CO) emissions: The concentration of CO in the exhaust gas when firing natural gas shall not exceed 15 ppmvd when firing natural gas and 20 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 48.0 lb/hr (when firing natural gas) and 65.0 lb/hr (when firing fuel oil) as indicated by EPA Method 10. [Rule 62-212.400, F.A.C.]

- Within 18 months after the initial compliance test on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest CO emission rate that can consistently be achieved firing natural gas. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the CO emission rate based upon this report. [BACT determination]

23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions (at ISO conditions) shall not exceed 1.1 pounds per hour when firing pipeline natural gas and 98.2 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. [Rule 62-212.400, F.A.C.]

24. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 or superior grade of fuel oil. Particulate matter emissions shall not exceed 9.0

lb/hr (front catch) while firing natural gas and 17.0 lb/hr (front catch) while firing fuel oil as indicated by opacity. [Rule 62-296.320(4)(b), F.A.C.]

25. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 2 ppmvd when firing natural gas and 3.5 ppmvd when firing fuel oil as assured by EPA Methods 18 and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 4.0 lb/hr (when firing natural gas) and 7.5 lb/hr (when firing fuel oil) as indicated by EPA Methods 18 and/or 25A. [Rule 62-212.400, F.A.C.]

EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open). 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 pursuant to Rule 62-210.700, F.A.C.

27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify RESD within (1) working day 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. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.

29. Initial (I) performance tests shall be performed on each unit while firing natural gas as well as while firing fuel oil, in accordance with Specific Condition 28. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after starting the CT) to air pollution control equipment, including low NO_X burners or SCR. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement).
- EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

30. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN technology while burning gas) or a 3-hr average (SCR technology or while burning oil). For the 24-hr block average (lb/hr) emissions may be determined via EPA Method 19 or equivalent EPA approved methods. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Conditions 26 and 27. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

31. Compliance with the SO_2 and PM/PM_{10} emission limits: Notwithstanding the requirements of Rule 62-297.310(7), F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-941 or D4294-90 (or equivalent latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent latest version) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

32. Compliance with CO emission limit: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for NO_X required pursuant to 40 CFR 75 (required for gas only).

33. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required.

34. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-204.800 F.A.C.

35. Test Notification: The DEP's Northeast District office and RESD shall be notified, in writing, at least 30 days prior to the initial performance tests and RESD notified at least 15 days before annual compliance test(s). [40 CFR 60.11]

36. Special Compliance Tests: The DEP or RESD may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

37. Test Results: Compliance test results shall be submitted to RESD no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by JEA shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP and RESD representatives upon request.

39. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition 37. above. 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), F.A.C.

40. Special Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to fuel usage:

(1) Hours of operation for each combustion turbine by fuel type shall be submitted with the Annual Operation Report (AOR) for the prior year.

(2) Hours of operation for each combustion turbine shall kept for each consecutive 12-month period by fuel type.

(3) Daily hours of fuel oil operation shall be kept for each combustion turbine during any day in which fuel oil is fired.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from each (CT) unit. Periods when NO_X emissions are above the standards as listed in Specific Condition No 21, shall be reported to RESD pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown and malfunction shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards listed in Specific Condition No. 21 except as noted in Specific Condition No. 30. [Rule 62-204.800 and 40 CFR 60.7 (1997 version)]

42. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). The calibration of the water/fuel-monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

43. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Northeast District Office as well as RESD no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the Brandy Branch Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- The permittee shall apply for an Acid Rain permit in compliance with the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant of 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
- JEA shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

46. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

JEA Brandy Branch Facility
PSD-FL-267 and 0310485-001-AC
Duval County, Florida

BACKGROUND

The applicant, JEA (formerly Jacksonville Electric Authority) proposes to install three nominal 170 megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Brandy Branch Facility near Baldwin City, Duval County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 90-foot stacks. JEA proposes to operate these units up to 4000 hours on natural gas and 800 hours on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated August 11, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on May 18, 1999 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch.

REVIEW GROUP MEMBERS:

Michael P. Halpin, P.E. and A. A. Linero, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	12 ppmvd @ 15% O_2 (gas) 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (800 hr/yr) Combustion Controls	10% Opacity
Carbon Monoxide	As Above	15 ppm (gas, baseload) 20 ppm (oil baseload)
Sulfur Dioxide	As Above	0.05% S in fuel oil
Sulfuric Acid Mist	As Above	0.05% S in fuel oil

According to the application, the maximum emissions from the facility will be approximately 858 tons per year (TPY) of NO_X, 366 TPY of CO, 75 TPY of PM/PM_{10}, 124 TPY of SO_2, 15 TPY of SAM, and 21 TPY of VOC.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by JEA is within the NSPS limit, which allows NO_X emissions, over 110 ppmvd for the high efficiency units to be purchased for the Brandy Branch Facility.

No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY EPA AND STATES:

The following table is based primarily on "F" Class intermittent-duty simple cycle turbines recently permitted or still under review. One project (PREPA) based on smaller units but permitted to operate continuously is included as an example of a simple cycle unit with add-on control equipment. Another continuous-duty project (Lakeland) based on the larger "G" Class is also included. The proposed JEA Brandy Branch project is included to facilitate comparison.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output and Duty	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Lakeland, FL	250 MW SC CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
Oleander Cocoa, FL	850 MW SC INT	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Draft 4/99. 1000 hrs on oil
JEA Brandy, FL	510 MW SC INT	12 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Application 5/99. 800 hrs on oil
JEA Kennedy, FL	170 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	170 MW GE MS7241FA CT Issued 2/99. Not PSD/BACT
TEC Polk Power, FL	330 MW SC INT	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Application 2/99. 876 hrs on oil
Dynegy Heard, GA	510 MW SC INT	15 – NG	DLN	3x170 MW WH 501F CTs Application. Gas only
Tenaska Heard, GA	960 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Application. 1687 hrs on oil
Dynegy Reidsville, NC	900 MW SC INT	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Draft 5/98. 1000 hrs on oil.
RockGen Cristiana, WI	525 MW SC INT	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
SEI Neenah, WI	330 MW SC INT	15/12 - NG 42 - No. 2 FO	DLN WI	2x165 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 8760/699 hrs gas/oil
PREPA, PR	248 MW SC CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous DLN = Dry Low NO_X Combustion FO = Fuel Oil GE = General Electric
SC = Simple Cycle SCR = Selective Catalytic Reduction NG = Natural Gas WH = Westinghouse
INT = Intermittent HSCR = Hot SCR WI = Water or Steam Injection ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
Oleander Cocoa, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Brandy, FL	15 - NG 20/26 (full/part load) - FO	1.4 – NG 1.4 – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
JEA Kennedy, FL	15 - NG 20 - FO	1.4 – NG 3.5 – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
SEI Neenah, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr - NG 41 lb/hr - FO	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from EPA dated September 10, 1999
- Comments from the Fish and Wildlife Service dated July 20, August 12 and August 30, 1999
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Brandy Branch Station Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combustion Turbine Startup Curves
- JEA Website – www.jea.com
- Goal Line Environmental Technologies Website – www.glet.com
- Catalytica Website – www.catalytica-inc.com

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the JEA project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 800 hours per year (per CT). Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the JEA Project. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection increase emissions of both of these pollutants.

Combustion Controls

The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the JEA project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at Jacksonville Electric Authority's Kennedy Station.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X and 9 ppm of CO. Emissions characteristics while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the JEA project are shown in Figure 4.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from gas turbines smaller than 200 MW (simple cycle), such as GE "F Class" units. Even lower NO_X emissions are achieved from certain units smaller than 100 MW, such as the GE 7EA line.

<u>Selective Catalytic Combustion</u>

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1125 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Per the above table, only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. SCR is also proposed on a permanent basis for the expansion of the FPC Hines Facility (Power Block II). Seminole Electric will install SCR on a previously-permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Permit limits as low as 2.25 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

Emerging Technologies: SCONOX™ and XONON™

There are at last two technologies on the horizon that will influence BACT determinations. These, as usual, are prompted by the needs specific to non-attainment areas such as Southern California.

The first technology is called $SCONO_X$™ and is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires a dilute hydrogen reducing gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[1] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at U.S. Generating's La Paloma Plant near Bakersfield.[2] The overall project includes several more 250 MW blocks with SCR for control.[3] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of some CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas.

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx™ process was deemed as technically feasible for maintaining NO_X emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). SCONOx requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the SCONOx system cannot be considered as achievable or demonstrated in practice for this application.

The second technology is XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as $SCONO_X$ ™ has. However GE has teamed with Catalytica to develop a combustor for gas turbines in the 80-90 MW range before continuing with development on a combustor for a larger unit. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

Catalytica's XONON™ system is represented as a powerful technology that essentially eliminates the formation of nitrogen oxides air emissions in gas turbines without impacting the turbine's operating performance. In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E-class and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil for up to 800 hours per CT as well as pipeline natural gas. The applicant estimated total emissions for the project at 124 TPY of SO_2 and 15 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 1 grain of sulfur per 100 standard cubic feet (gr S/100ft^3). This value is well below the "default" maximum value of 20 gr. S/100 ft^3, but high enough to require a BACT determination.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 800 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 75 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations typically achieve emissions between 10 and 25 ppm at full load while firing gas. The values of 15 and 20 ppm for gas and oil respectively at baseload proposed in JEA's original application are within the range of recent determinations for simple cycle CO BACT determinations. By comparison, values of 12 and 20 ppm for gas and oil respectively (at baseload) were proposed for the Oleander's project using identical equipment. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by JEA for this project are 1.4 ppm for both gas and oil firing at baseload. According to GE, however, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[5] By comparison, limits of 3 and 6 ppm were proposed for gas and oil firing respectively in the Oleander application. The limits proposed by JEA are sufficiently low to exempt the Brandy Branch project from BACT for VOC.

BACKGROUND ON PROPOSED GAS TURBINE

JEA plans the purchase of three 170 MW (nominal) General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

The first commercial GE 7F Class unit was installed in a combined cycle project at the Virginia Power Chesterfield Station in 1990.[6] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[7] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppm of CO, and 0-0.17 ppm of VOC.[8] The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[9] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[10] FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for six GE 7241FA turbines to be installed at the Fort Myers Repowering project.[11] The Santa Rosa Energy Center in Pace, Florida, also received a permit with a 9 ppmvd NO_X limit for a GE 7241 turbine with DLN-2.6 burners.[12]

Most recently, the Department issued draft BACT determinations for the simple cycle Oleander project in Brevard County and the combined cycle projects in Volusia (Duke Energy) and Osceola County (Kissimmee Utilities). These three draft permits also include NO_X limits of 9 ppmvd based on the DLN-2.6 technology installed on F Class units.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[13] In its recent permits, Florida has included separate and lower limits in the event that DLN emissions limits are not attainable or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[14] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[15] Unit 2 is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line such as the one that will be installed for the JEA Brandy Branch Project. Performance guarantees less than 9 ppmvd can be expected for DLN-2.6 combustors on units delivered in a couple of years.[16]

The 12 ppmvd NO_X limit on natural gas proposed by JEA is a fairly stringent BACT determination for simple cycle F Class, though it is becoming less so. The company has obtained a guarantee from GE to achieve 9 ppmvd, which is for a performance test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation as specified in the GE protocols.

With the frequent start-ups and shutdowns of the unit, JEA is concerned about the ability to maintain the low (9 ppmvd) NO_X values for long periods of time following the performance tests. Presumably, this concern would be lessened should these units be converted to a more continuous duty (i.e. combined cycle). Although the Department is not fully aware of the details of the GE guarantee for Oleander (proposed 9 ppmvd on a simple cycle unit), the Department is aware from discussions with other applicants that a continuing guarantee is available at a substantial cost.[17]

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low NO_X techniques, fuel staging and combustion mode are also controlled by the Mark V, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V.[18]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the JEA project assuming full load. Values for NO_X are corrected to 15% O_2 on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 20 through 25.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}	Pipeline Natural Gas Good Combustion	10 Percent Opacity 9 lb/hr – Gas 17 lb/hr – Fuel Oil
CO	As Above	12* ppm – Gas 20 ppm – Fuel Oil
SO_2/SAM	As Above	2 grains of sulfur per 100 ft^3 gas 0.05 percent sulfur in fuel oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	10.5 ppmvd – Gas 42* ppmvd – F.O. for 750 of 4750hours

* See discussion below.

RATIONALE FOR DEPARTMENT'S DETERMINATION

- JEA has agreed to shutdown its Southside facility, also located in Duval County. This will result in a net decrease of regulated pollutants which are emitted.
- General Electric has provided a "clean and new" one-time guarantee of 9 ppmvd NO_X.
- Typical "continuous" permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 12-15 ppmvd even though GE provides the same "new and clean" guarantees for them. Limits as high as 25 ppmvd have been recently proposed by some for similar units produced by other manufacturers.
- A level of 9 ppmvd NO_X by DLN has been demonstrated on GE 7FA combustion turbines at Fort St. Vrain, Colorado and Clark County, Washington. However the permitted limits are actually higher at these two facilities providing some level of operating margin.
- A limit of 9 ppmvd was proposed by Oleander for five GE7 FA units and is reflected in the Department's recent Draft BACT Determination for that facility. A BACT level of 9 ppmvd has been proposed by Virginia Power for a GE 7FA unit to avoid non-attainment New Source Review.
- The proposed 9 ppmvd limit at Oleander and Virginia Power while firing natural gas is the lowest known Draft BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42 ppmvd limit while firing fuel oil is typical.
- The Department prepared a Draft permit for the TEC Polk Power Station Project adopting TEC's proposed 10.5 ppmvd limit for two GE 7FA units, but limited the hours of operation on fuel to less than the hours allowed at Oleander. The TEC Draft BACT is being issued concurrently with the Draft BACT for the JEA project.
- JEA's proposed 12 ppmvd limit for the Brandy Branch Facility while firing natural gas is relatively low for a GE 7FA Class simple cycle, intermittent duty unit.
- The Department however, proposes a BACT limit of 10.5 ppmvd, which is the same as proposed for the TEC project. The Department also proposes to limit oil firing to the same number of hours as TEC (750) and less than the number of hours at Oleander (1000). Considering the applicant's shutdown of its Southside facility in conjunction with the Department's BACT limits, net annual NO_X emissions (TPY) will be approximately zero.
- The Department will still require JEA to meet to meet the "clean and new" limit of 9 ppmvd during initial testing as well as requiring a continuous 9 ppmvd guarantee (or better) in the event that JEA converts the units to continuous duty (i.e. combined cycle).
- The proposed BACT limit of 10.5 ppmvd is about one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- The units will be operated in simple cycle mode. Therefore control options, which are feasible for combined cycle units, are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 4.5 ppmvd NO_X or lower. It also rules out the possibility of SCONOx. XONON is not available for F Class dual fuel projects.
- The simple cycle "F Class" turbines have very high exhaust temperatures of up to 1200 °F. Without additional cooling, this is at the higher limit of the present operational temperature of

Hot SCR zeolite catalyst (around 1125°F). The PREPA simple cycle turbines, which use Hot SCR, have exhaust temperatures ranging from 824 to 1024°F and burn exclusively #2 oil.

- The levelized costs of NO_X removal by Hot SCR for the JEA project were estimated by Black & Veatch at $13,380 per ton assuming 4000 hours of operation on natural gas and a reduction from 12 to 5 ppmvd. The Department estimates that this figure is reduced by including oil operation (up to 750 hours per year) and other criteria, but still exceeds $7,000 per ton.
- TEC estimated the cost of Hot SCR at $9,717 per ton of NO_X removed assuming 4,380 and 876 hours per year of operation on gas and oil respectively.
- The Department previously concluded that Hot SCR is cost-effective for continuous duty simple cycle service (Lakeland). EPA also concluded Hot SCR is cost-effective on continuous duty simple cycle projects (PREPA).
- Although the Department does not have a "bright line" cost-effectiveness figure and does not necessarily adopt the precise cost calculations for the JEA and TEC projects, the values projected by JEA and TEC indicate that Hot SCR is not cost-effective for their respective projects.
- Comments from the National Park Service on the Oleander project suggested that a reduction in the applicant's proposed NO_X emissions on oil from 42 ppmvd to 25 ppmvd is possible based on reported oil-fired units listed in the BACT Clearinghouse. GE has advised that it only offers a 42 ppmvd NO_X guarantee on F Class units when firing oil.
- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- It is possible that the NO_X emissions while firing oil from may be reduced from 42*ppmvd by increasing the water injection rate. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil have been achieved.
- The Department's overall BACT determination is equivalent to approximately 0.5 lb./MW-hr NO_X emissions for combined gas and oil operation. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr. FDEP BACT analyses typically target values less than 1.0 lb./MW-hr for simple cycle CT's and less than 0.5 lb./MW-hr for combined cycle units.
- VOC emissions of 1.4 ppm while firing gas or oil proposed by the applicant clearly reflect BACT and, in fact, exempt the project from a BACT determination for VOC. The Department will set VOC limits at 2 ppm (gas) and 3.5 ppm (oil). These values are still sufficient to maintain VOC emissions to less than 40 tons per year.
- The Department will set CO limits achievable by good combustion at full load as 12* ppm (gas) and 20 ppm (oil). These values are equal to the lowest values from permitted or proposed simple cycle units and are equal to those proposed by the Department for Oleander and TEC project. Due to the applicant's (higher) guarantee while firing gas of 15 ppm, the specific permit condition will be worded so as to allow for initial 15 ppm operation with a requirement

to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable CO emission rates while firing gas have been achieved.

- Black & Veatch evaluated the use of an oxidation catalyst for the JEA project with an 88 percent control efficiency and having a three-year catalyst life. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,905,000 with an annualized cost of $509,000 per year. Levelized costs for CO catalyst control were calculated at $4,700 per ton. This figure does not appear to be cost-effective for removal of CO.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels for limited hours, and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 750 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, Santa Rosa Energy Center, FPL Fort Myers, and the Southern Company Barry projects.

Compliance Procedures

POLLUTANT	COMPLIANCE PROCEDURE
Particulate Matter	Method 9
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)
NO_X (24-hr block average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
SO_2 and SAM	Custom Fuel Monitoring Schedule

<u>DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:</u>

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10/13/99
Date:

Approved By:

CHFancy

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

10/13/99
Date:

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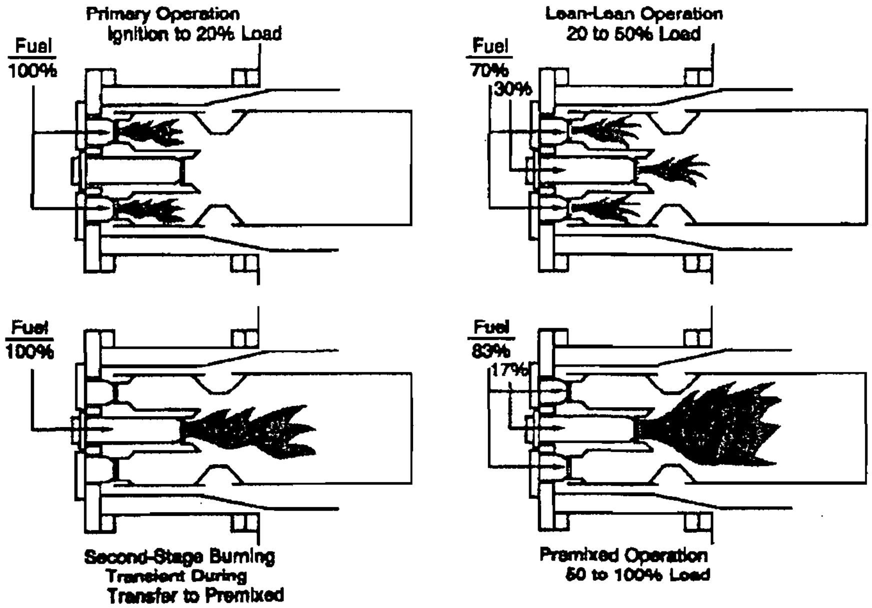

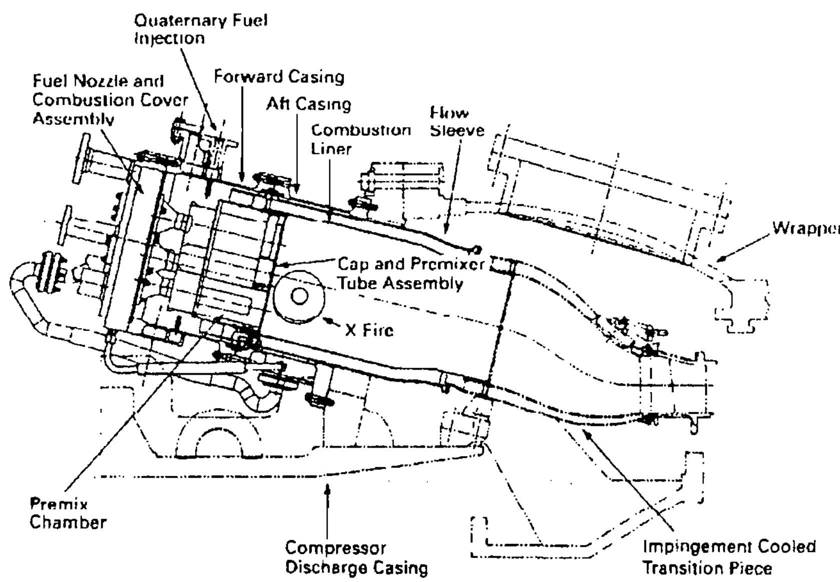

Figure 1 - Dry Low NOx Operating Modes - DLN-1

Cross Section of GE DLN-2

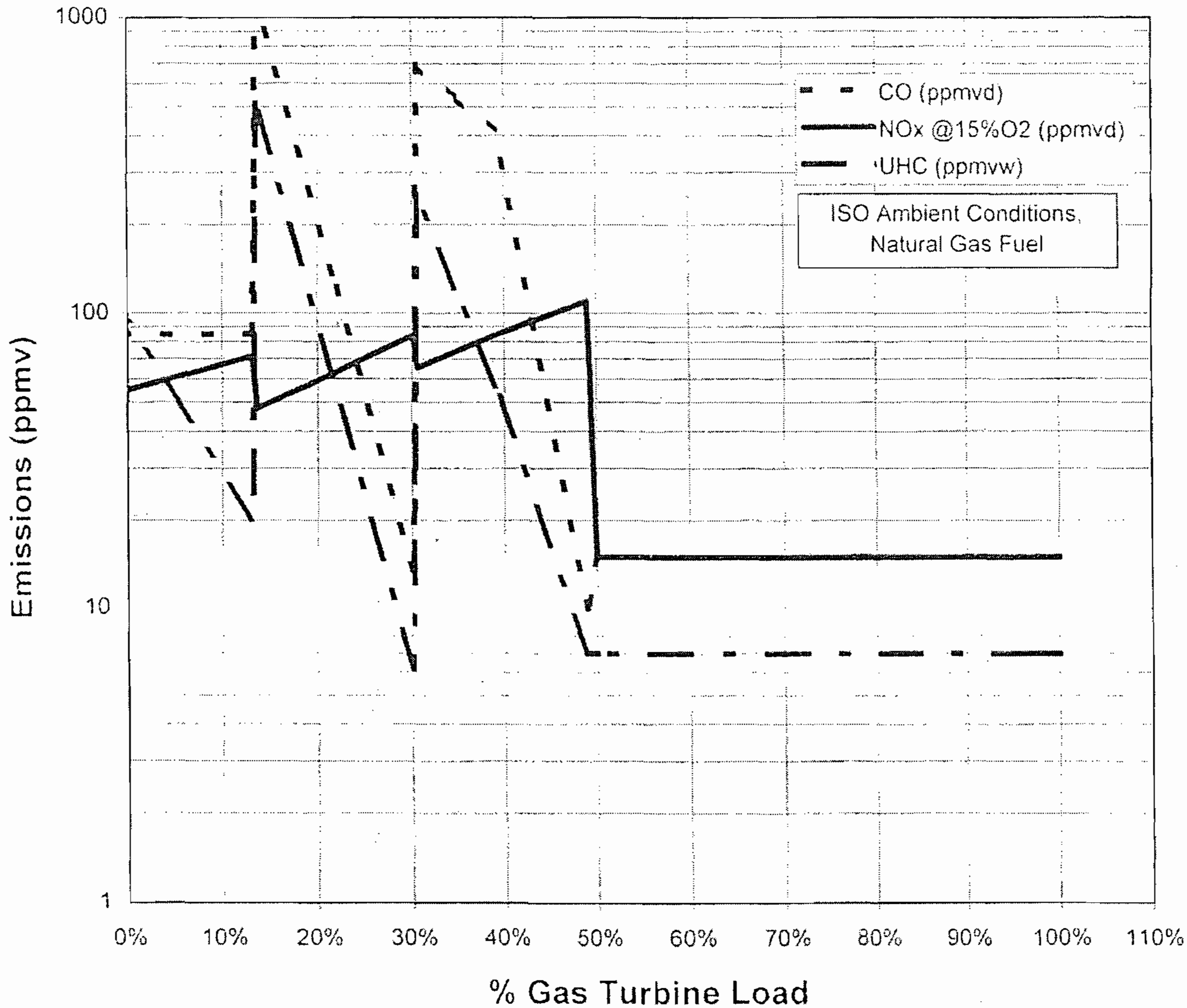

Figure 2 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NO_X)

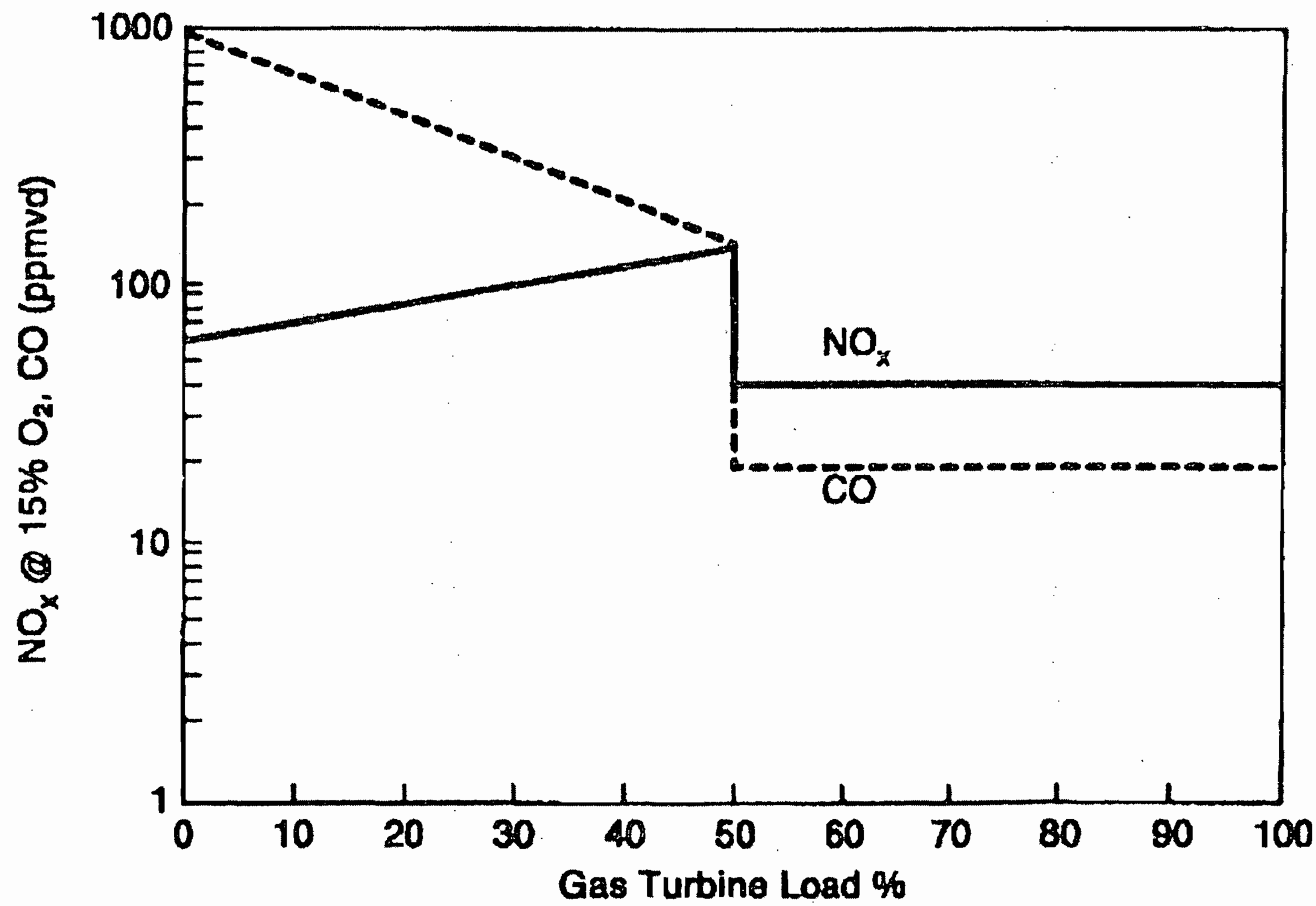

Figure 3 – Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

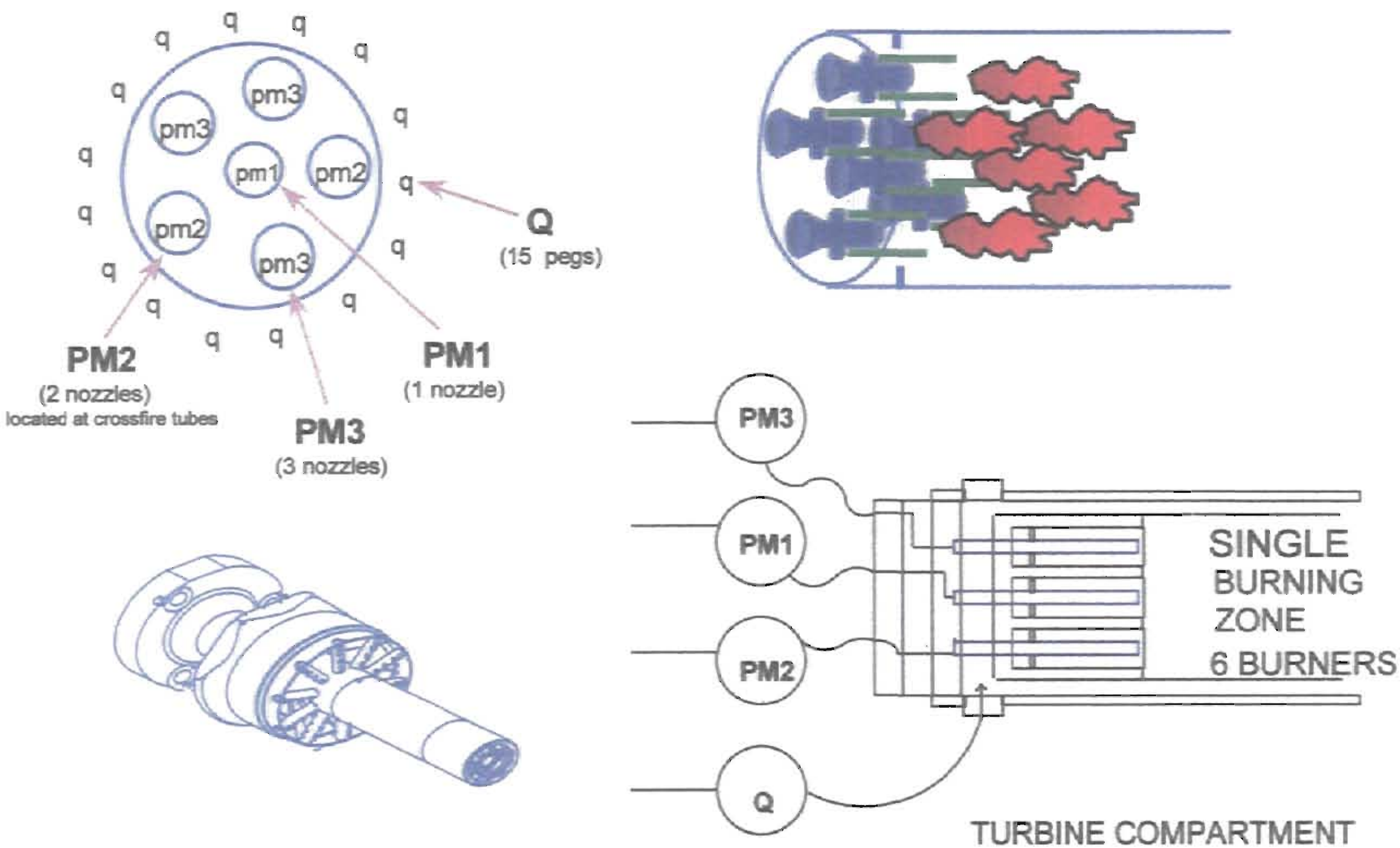

Figure 4 - DLN-2.6 Nozzle and Burner Arrangement

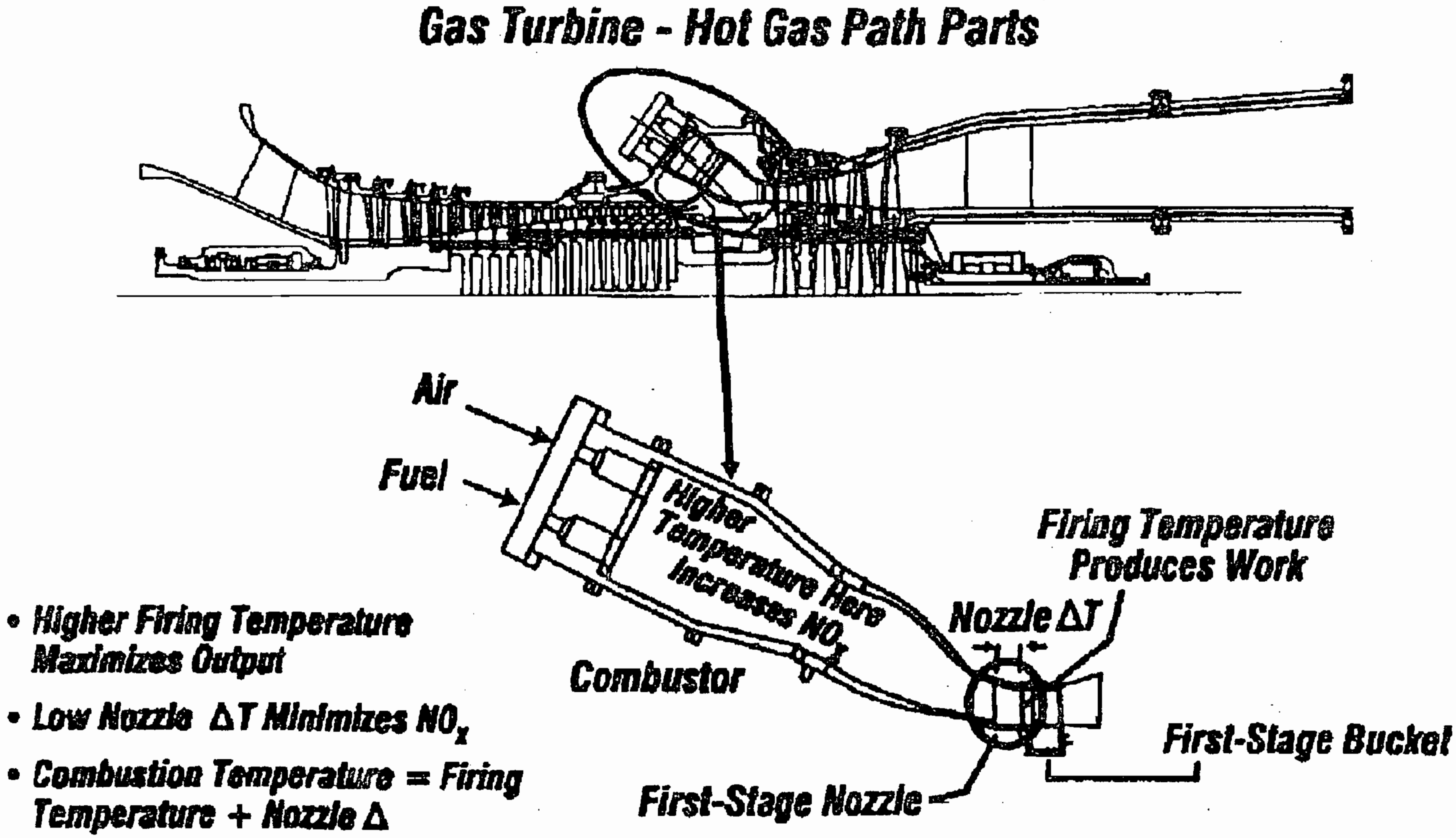

Figure 5 - Relation Between Flame Temperature and Firing Temperature

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

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

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver 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.

APPENDIX GC
GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

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 ( )
b) Determination of Prevention of Significant Deterioration ( ); 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.

Florida Department of
Environmental Protection

Memorandum

TO: Howard L. Rhodes

THRU: Clair Fancy
Al Linero aaf 10/12

FROM: Mike Halpin

DATE: October 11, 1999

SUBJECT: JEA Brandy Branch PSD Permit

Attached for approval and signature is an air construction permit for the subject (new) facility. The Public Notice requirements have been met on August 23, 1999 by publishing in the Florida Times-Union. The applicant filed for and received an enlargement of time in which to file a petition for Administrative Proceeding. This expired on October 1, 1999.

Comments were received by the US EPA, US Fish and Wildlife Service as well as the applicant and are addressed within the Final Determination.

I recommend your approval and signature.

Day 90 is 12/3/99.

Attachments

/mph

Clair - These guys ran CALPUFF and passed
They reduced fuel oil burning to max of 16 hrs/day
+750 hrs/year
They made shutdown of Southside a commitment.
Let's give them their permit promptly!
Thanks Al

RECEIVED

OCT 08 1999

BUREAU OF AIR REGULATION

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

OGC CASE NO.: 99-1440
FDEP File No.: 0310485-001AC (PSD-FL-267)

JEA
Brandy Branch Facility
Duval County, Florida
_______________________________________/

NOTICE OF WITHDRAWAL OF EXTENSION OF TIME

JEA by and through undersigned counsel, hereby withdraws its Request for Extension of Time to file a petition for formal administrative proceedings in accordance with Chapter 120, Florida Statutes. JEA filed its last Request for Extension of Time until November 1, 1999, in response to the "Intent to Issue Air Construction Permit" (FDEP File No.: 0310485-001-AC (PSD-FL-267)) for the JEA Brandy Branch facility located in Duval County, Florida to negotiate certain changes in the Draft permit with the Department of Environmental Protection (Department). Following discussions with Department representatives, JEA and the Department came to an agreement on the issues involved in the above-referenced Draft permit, as reflected in the attached document. Conditioned upon the Department's issuance of the Final permit in accordance with our agreement, JEA hereby withdraws its Request for Extension of Time.

Respectfully submitted this 7 day of October, 1999.

HOPPING GREEN SAMS & SMITH, P.A.

By: Robert A. Manning
Robert A. Manning
Florida Bar No. 0035173
Post Office Box 6526
Tallahassee, FL 32314
(850) 222-7500

ATTORNEYS FOR JEA

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 7 day of October, 1999:

Al Linero
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Doug Beason, Esq.
Department of Environmental Protection
Room 669
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Clair Fancy
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Robert A. Manning
Attorney

PERMITTEE:

Jacksonville Electric Authority
Brandy Branch Facility
21 West Church Street
Jacksonville, Florida 32202-3139
Authorized Representative:

Walter P. Bussells, Chief Executive Officer

File No.	PSD-FL-267
FID No.	0310485
SIC No.	4911
Expires:	12/31/02

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators and three 90-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability. They are designated by JEA as Combustion Turbine Generators 1, 2 and 3 and by the Department as ARMS Emissions Units 001, 002 and 003.

The project will be located approximately 1 mile N.E. of Baldwin City, Duval County. UTM coordinates are: Zone 17; 408.81 km E; 3354.38 km N.

STATEMENT OF BASIS:

This PSD 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 40CFR51.166. The above named permittee is authorized to modify the facility 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 of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with three 90-foot stacks and three fuel oil storage tanks.

Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSIONS UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One nominal 170 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
005	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
006	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

The 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 (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 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). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 08/23/99 Notice of Intent published in The Florida Times-Union
- 08/12/99 Distributed Intent to Issue Permit
- 08/06/99 Application deemed complete
- 05/18/99 Received Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on May 18, 1999
- Department letters dated May 26 and July 21, 1999
- Comments from the Fish and Wildlife Service dated July 20, August 12 and August 30, 1999
- Letter from JEA dated June 21, 1999
- Letter (e-mail) from JEA dated August 4, 1999 and related submittals
- Department's Intent to Issue and Public Notice Package dated August 12, 1999
- Letters (e-mail) from JEA dated August 27 and September 24, 1999
- Letter (facsimile) from EPA dated September 10, 1999
- Letter from Golder Associates Inc. dated September 10, 1999 and regional haze analysis
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: 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 (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Northeast District office, 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256 and phone number 904/448-4300; additionally, such documents shall be submitted to RESD, Suite 225, 117 W. Duval St., Jacksonville, Florida 32202 and phone number 904/630-3484.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: 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. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [62-4.070(4), 62-4.210(2)&(3), 62-210.300(1)(a)].
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 51.166(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation (e.g. conversion to combined-

cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166, Rule 62-4.070 F.A.C.]

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Northeast District office as well as RESD. [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Northeast District office as well as RESD by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit [Rule 62-4.080, F.A.C.]

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to RESD. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

14. Retirement of existing facility: In accordance with JEA's analyses of regional haze in the nearby Class I areas, the Brandy Branch facility may cause or contribute to haze values greater than 5%. In order to mitigate this possibility, JEA will limit the operation of the combustion turbines permitted herein to a maximum of 16 hours per day of oil operation. Additionally, so as to cause a net benefit to the nearby Class I areas, JEA shall retire the existing Southside Facility (AIRS ID 0310046) located at 801 Colorado Avenue, Jacksonville, Florida upon JEA's application for a Title V permit for the Brandy Branch facility (including certification that the facility is in compliance with applicable requirements and permit conditions). JEA shall concurrently submit a letter from the designated representative of the Southside facility certifying that the facility has been shutdown and that related permits are being surrendered. This shall occur on or before October 31, 2002.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

- 40CFR60.7, Notification and Recordkeeping
- 40CFR60.8, Performance Tests
- 40CFR60.11, Compliance with Standards and Maintenance Requirements
- 40CFR60.12, Circumvention
- 40CFR60.13, Monitoring Requirements
- 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines (with optional evaporative inlet cooling) shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]

5. ARMS Emission Units 004-006, Fuel Storage, consisting of three 1 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

6. All notifications and reports required by the above specific conditions shall be submitted to RESD.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] {Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,623 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,822 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. {Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 95-100 percent of the emissions unit's rated capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in this permit requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods (including but not limited to) fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the operator to calculate average hourly heat input during the test.} [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. 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.]

10. 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 owner or operator shall notify the DEP Northeast District office and RESD as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the 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 and the regulations. [Rule 62-4.130, F.A.C.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]
13. Maximum allowable hours: Each stationary gas turbine shall only operate up to 4750 hours during any consecutive twelve month period, of which 750 hours of operation per combustion turbine may be while firing oil. Additionally, each turbine shall be limited to 16 hours per day of oil firing. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
14. [DELETED]
15. [DELETED]

Control Technology

16. Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine to control NO_X emissions while firing natural gas. [BACT, Rule 62-4.070, F.A.C.]
17. The permittee shall design each stationary combustion turbine, ducting, and stack(s) so as to not preclude installation of SCR equipment and/or oxidation catalyst in the event of a failure to achieve the NO_X limits given in Specific Condition No. 20 and 21 or the carbon monoxide (CO) limits given in Specific Condition 22. [Rule 62-4.070, F.A.C.]
18. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070, 62-212.400, F.A.C.]
19. Consistent with best operation and maintenance practices, the DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rules 62-4.070, 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

20. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15% O_2 on a dry basis. [Rule 62-212.400, F.A.C.]

Operational Mode (Fuel)	NO_X (15%O2)	CO	VOC	PM/Visibility (% Opacity)	SO_2/SAM	*Technology and Comments*
Natural Gas	10.5 ppm	12 ppm	2 ppm	10	2 grain S per 100 CF	Dry Low NOx Burners. Clean fuels, good combustion
Fuel Oil	42 ppm	20 ppm	3.5 ppm	10	0.05% sulfur oil	Water Injection. Units limited to 750 hrs equivalent full load oil operation (per CT) annually. Clean fuels, good combustion

NOTE: The VOC limit imposed herein was not determined by BACT.

21. Nitrogen Oxides (NO_X) Emissions:

- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- While firing Natural Gas: The emission rate of NO_X in the exhaust gas shall not exceed 69.3 lb/hr (at ISO conditions) on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 10.5 ppm @15% O_2 to be demonstrated by annual stack test nor 9 ppm @15% O_2 to be demonstrated by the initial "new and clean" GE performance stack test. Note: Basis for lb/hr limit is 10.5 ppm @ 15% O_2, full load. [Rule 62-212.400, F.A.C.]
- While firing Fuel oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 42 ppm @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- After combusting fuel oil for at least 400 hours on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest NO_X emission rate that can consistently be achieved when firing distillate oil. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the NO_X emission rate based upon this report. [BACT determination]

22. Carbon Monoxide (CO) emissions: The concentration of CO in the exhaust gas when firing natural gas shall not exceed 15 ppmvd when firing natural gas and 20 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 48.0 lb/hr (when firing natural gas) and 65.0 lb/hr (when firing fuel oil) as indicated by EPA Method 10. [Rule 62-212.400, F.A.C.]

- Within 18 months after the initial compliance test on any individual CT, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest CO emission rate that can consistently be achieved when natural gas. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the CO emission rate based upon this report. [BACT determination]

23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions (at ISO conditions) shall not exceed 1.1 pounds per hour when firing pipeline natural gas and 98.2 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. [Rule 62-212.400, F.A.C.]

24. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 or superior grade of fuel oil. Particulate matter emissions shall not exceed 9.0

lb/hr while firing natural gas and 17.0 lb/hr while firing fuel oil as indicated by opacity. [Rule 62-296.320(4)(b), F.A.C.]

25. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 2 ppmvd when firing natural gas and 3.5 ppmvd when firing fuel oil as assured by EPA Methods 18 and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 4.0 lb/hr (when firing natural gas) and 7.5 lb/hr (when firing fuel oil) as indicated by EPA Methods 18 and/or 25A. [Rule 62-212.400, F.A.C.]

EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open). 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 pursuant to Rule 62-210.700, F.A.C.

27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify RESD within (1) working day 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. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.

29. Initial (I) performance tests shall be performed on each unit while firing natural gas as well as while firing fuel oil, in accordance with Specific Condition 28. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after starting the CT) to air pollution control equipment, including low NO_X burners or SCR. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).

- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement).
- EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

30. <u>Continuous compliance with the NO_X emission limits</u>: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN technology while burning gas) or a 3-hr average (SCR technology or while burning oil). For the 24-hr block average (lb/hr) emissions may be determined via EPA Method 19 or equivalent EPA approved methods. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Conditions 26 and 27. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

31. <u>Compliance with the SO_2 and PM/PM_{10} emission limits</u>: Notwithstanding the requirements of Rule 62-297.310(7), F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-941 or D4294-90 (or equivalent latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent latest version) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

32. <u>Compliance with CO emission limit</u>: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for NO_X required pursuant to 40 CFR 75 (required for gas only).

33. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required.

34. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-204.800 F.A.C.

35. Test Notification: The DEP's Northeast District office and RESD shall be notified, in writing, at least 30 days prior to the initial performance tests and RESD notified at least 15 days before annual compliance test(s). [40 CFR 60.11]

36. Special Compliance Tests: The DEP or RESD may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

37. Test Results: Compliance test results shall be submitted to RESD no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by JEA shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP and RESD representatives upon request.

39. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition 37. above. 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), F.A.C.

40. Special Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to fuel usage:

(1) Hours of operation for each combustion turbine by fuel type shall be submitted with the Annual Operation Report (AOR) for the prior year.

(2) Hours of operation for each combustion turbine shall kept for each consecutive 12-month period by fuel type.

(3) Daily hours of fuel oil operation shall be kept for each combustion turbine during any day in which fuel oil is fired.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from each (CT) unit. Periods when NO_X emissions are above the standards as listed in Specific Condition No 21, shall be reported to RESD pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown and malfunction shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards listed in Specific Condition No. 21 except as noted in Specific Condition No. 30. [Rule 62-204.800 and 40 CFR 60.7 (1997 version)]

42. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). The calibration of the water/fuel-monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

43. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Northeast District Office as well as RESD no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the Brandy Branch Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- The permittee shall apply for an Acid Rain permit in compliance with the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant of 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USAEPA.
- JEA shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

46. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

10-4-99

104

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

JACKSONVILLE ELECTRIC AUTHORITY,

Petitioner,

vs. OGC CASE NO. 99-1440

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Respondent.
_________________________________/

ORDER GRANTING REQUEST FOR EXTENSION
OF TIME TO FILE PETITION FOR HEARING

This cause has come before the Florida Department of Environmental Protection (Department) on receipt of a request made by Petitioner, Jacksonville Electric Authority, to grant an extension of time to file a petition for an administrative hearing on Permit No. 0310485-001-AC. See Exhibit 1.

Respondent, State of Florida Department of Environmental Protection, has no objection to it. Therefore,

IT IS ORDERED:

The request for an extension of time to file a petition for administrative proceeding is granted. Petitioner shall have until November 15, 1999, to file a petition in this matter. Filing shall be complete on receipt by the Office of General Counsel, Mail Station 35, Department of Environmental Protection, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000.

DONE AND ORDERED on this 29th day of September, 1999, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

BH for Jack Chisolm

F. PERRY ODOM
General Counsel

Douglas Building, MS #35
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000
Telephone: (850) 488-9314

CERTIFICATE OF SERVICE

I CERTIFY that a true copy of the foregoing was mailed to:

Robert A. Manning, Esq.
Post Office Box 6526
Tallahassee, Florida 32314-6526

on this 4th day of ~~September~~ October, 1999.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

W. D. B.

W. DOUGLAS BEASON
Assistant General Counsel
Florida Bar No. 379239

Mail Station 35
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000
Telephone: (850) 488-9314

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

OGC CASE NO.:
FDEP File No.: 0310485-001AC (PSD-FL-267)

JEA
Brandy Branch Facility
Duval County, Florida
_______________________________________/

RECEIVED
AUG 27 1999
DEPARTMENT OF
ENVIRONMENTAL PROTECTION
OFFICE OF GENERAL COUNSEL

REQUEST FOR ENLARGMENT OF TIME

By and through undersigned counsel, JEA (formerly known as the Jacksonville Electric Authority) hereby requests, pursuant to Florida Administrative Code Rule 62-110.106(4), an enlargement of time, to and including October 1, 1999, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, JEA states the following:

1. The Department of Environmental Protection (Department) issued an "Intent to Issue Air Construction Permit" (FDEP File No.: 0310485-001-AC (PSD-FL-267)) for the JEA Brandy Branch facility located in Duval County, Florida, dated August 11, 1999. Along with the Intent to Issue, the Department issued a Draft Air Construction Permit and "Public Notice of Intent to Issue Air Construction Permit."

2. JEA received an unsigned version of this Intent to Issue by e-mail on August 12, 1999.

3. Based on JEA's review, the Draft Permit and associated documents contain several provisions that warrant clarification or correction.

128805

EXHIBIT 1

4. This request is filed simply as a protective measure to avoid waiver of JEA's right to challenge certain conditions contained in the Draft Permit. Grant of this request will not prejudice either party, but will further their mutual interest and hopefully avoid the need to file a petition and proceed to a formal administrative hearing. If the Department denies this request, JEA requests the opportunity to file a Petition for Administrative Proceeding within 10 days of such denial.

WHEREFORE, JEA respectfully requests that the time for filing of a Petition for Administrative Proceedings in regard to the Department's Intent to Issue Air Construction Permit for FDEP File No.: 0310485-001-AC (PSD-FL-267) be formally extended to and including October 1, 1999.

Respectfully submitted this 26 day of August, 1999

HOPPING GREEN SAMS & SMITH, P.A.

By: Robert A. Manning

Robert A. Manning
Florida Bar No. 0035173
Post Office Box 6526
Tallahassee, FL 32314
(850) 222-7500

ATTORNEYS FOR JEA

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 21 day of August, 1999:

Al Linero
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Scott Goorland, Esq.
Department of Environmental Protection
Room 669
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Clair Fancy
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Robert A. Manning
Attorney

128805

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

OGC CASE NO.:
FDEP File No.: 0310485-001AC (PSD-FL-267)

JEA
Brandy Branch Facility
Duval County, Florida
_______________________________________/

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2. JEA received an unsigned version of this Intent to Issue by e-mail on August 12, 1999.

128805

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WHEREFORE, JEA respectfully requests that the time for filing of a Petition for Administrative Proceedings in regard to the Department's Intent to Issue Air Construction Permit for FDEP File No.: 0310485-001-AC (PSD-FL-267) be formally extended to and including November 1, 1999.

Respectfully submitted this 30 day of September, 1999

HOPPING GREEN SAMS & SMITH, P.A.

By: Robert A. Manning

Robert A. Manning
Florida Bar No. 0035173
Post Office Box 6526
Tallahassee, FL 32314
(850) 222-7500

ATTORNEYS FOR JEA

<u>**CERTIFICATE OF SERVICE**</u>

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this ______ day of September, 1999:

Al Linero
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Scott Goorland, Esq.
Department of Environmental Protection
Room 669
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Clair Fancy
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

____
Attorney

INTEROFFICE MEMORANDUM

Date: 24-Sep-1999 12:12pm
From: Gianazza, N. Bert
GianNB@jea.com
Dept:
Tel No:

To: Mike Halpin (Halpin_M@dep.state.fl.us)
To: Mike Halpin2 (mphalpin@prodigy.net)

Subject: Comments on Brandy Branch

MIME-Version: 1.0
Content-type: text/plain; charset=ISO-8859-7

Hi Mike. Below are our comments on the BB permit.

(1) All citations to 40 CFR 52.21 should be deleted from the permit and statement of basis. 40 CFR 52.21 only applies to states that do not have their own PSD program. For states that have their own PSD program, 40 CFR 51.166 applies. Specifically, Conditions 6 and 7 continue to cite 52.21 as authority, inappropriately. Condition 6 should be deleted in its entirety because it is solely derived from 40 CFR 52.21; a comparable provision does not exist in 40 CFR 51.166 or state law. Condition 7 is not necessary because the Brandy Branch project is not a "phased construction project." If the Department believe this condition is necessary, it should be limited to an exact quote of 40 CFR 51.166(j)(4) the first and last sentences of this condition are unnecessary and inappropriate.

(2) JEA requests that the possibility of installing an evaporative inlet cooler (fogger) be referenced in the permit itself, and not only in the Technical Evaluation. ok

(3) Condition 8. JEA appreciates the Department's inclusion of a permitting note clarifying the purpose for including the heat input values. To be consistent with other recently issued Title V permits, JEA also requests that the Department include the entire permitting note reflected in the attached proposed permit. I will send or fax this language separately.

(4) Condition 19. For clarification, JEA requests that this condition read as follows: "Consistent with normal operation and maintenance practices, the DLN systems shall each be tuned . . . ." ok

(5) Condition 21. JEA appreciates the Department's concurrence of the need to require the submittal of an engineering report only after a CT burns oil at least 400 hours. However, JEA does not believe the revised permit language accomplishes this result. Accordingly, JEA requests that the first sentence of the fourth bullet read as follows: "After combusting fuel oil for at least 400 hours on any individual CT, the permittee shall prepare . . . ." This language would require JEA to submit the report whenever a CT burned at least 400 hours, whether this occurred more or less than 18 months after the initial compliance test. Also, the first bullet in Condition 21 is not appropriate because the missing data procedures under 40 CFR Part 75 are designed to assure compliance with an annual limit, not a short term limit. Accordingly, JEA requests that this bullet be deleted. ok

(6) Condition 22. In accordance with our vendor guarantee and the permit application, please revise the CO limit on gas from 12 ppm to 15 ppm. Also, both the oil and gas guarantees are for full load only, therefore we request that clarifying language be added that states that the limit and stack testing requirements are for full load conditions only. (Note: Since automobiles account for about 90% of the CO emissions inventory in Duval, and the entire JEA system accounts for only about 2% of the CO emissions inventory for Duval, the CO emissions from these units will have no significant effect on ambient air quality.) OK

(7) Condition 24. BACT for particulate matter was determined to be good combustion practices and an opacity limit of 10 percent. It is not necessary or appropriate to include a PM limit in a condition regarding visible emissions, especially where the BACT does not impose a PM limit. Also, JEA does not object to the removal of the language regarding a 20 percent opacity limit during startup and shutdown, but notes that Condition 26 allows excess emissions for a period of 2 hours in any 24 hour period resulting from startup, shutdown and malfunction. NO

(8) Condition 43. JEA appreciates the Department's agreement to make this condition consistent with other permitting actions, but does not believe the language is consistent with 40 CFR 75.62. Accordingly, JEA requests that the last sentence of this condition read as follows: "Data on CEM equipment specifications . . . be provided to the Department's Northeast District Office as well as RESD no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62." The existing permit language, inappropriately, requires the submittal of this data 90 days prior to the certification test. OK

(9) While our initial aggressive schedule for the installation of these units called for having all three in commercial operation in the year 2001, it is possible that circumstances will result in the last of the three units not being released for commercial operation until sometime in the year 2002. For this reason, we request a permit expiration date of 12/31/02. OK

If you have any questions with regard to the above comments or would like to talk to me about any of these issues, please do not hesitate to call me.

Tx, Bert

10/6/? NK

10/1/98

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

September 10, 1999

RECEIVED 9937577B

SEP 13 1999

BUREAU OF AIR REGULATION

Bureau of Air Quality Management
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attention: Mr. Cleve Holladay

RE: REFINED REGIONAL HAZE ANALYSES FOR THE PROPOSED JEA BRANDY BRANCH FACILITY - DRAFT

Dear Cleve:

Please find enclosed two report copies of the refined regional haze analysis for Jacksonville Electric Authority's proposed Brandy Branch facility. Included with the report is a CD containing all data files and modeling input and output files used in the analysis. Should you have any questions or comments about the report or files, please contact me. Thank you.

Sincerely,

GOLDER ASSOCIATES INC.

Steven R. Marks

Steven R. Marks, CCM
Senior Scientist

SRM/jkk

Enclosures

cc: B. Giannazza, JEA
M. Bareta, B&V
E. Porter, USFWS
S. Krivo, EPA Region IV

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

SEP 10 1999

RECEIVED
SEP 17 1999
BUREAU OF AIR REGULATION

4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and Draft Permit for Jacksonville Electric Authority - Brandy Branch Project (PSD-FL-267) located in Duval County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft permit dated August 11, 1999, for the above referenced facility. The preliminary determination is for the proposed construction and operation of a new electric power generating station consisting of three simple cycle combustion turbines (CTs) with a nominal generating capacity of 170 MW each. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. Additional equipment will include the following: three 1 million gallon fuel oil storage tanks and one small diesel fire-water pump. The CTs will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. The fire-water pump will combust only diesel fuel. Each CT will be allowed to fire natural gas a maximum of 4,000 hours per year and will be allowed to fire No. 2 fuel oil a maximum of 750 hours per year. Total emissions from the proposed project are above the thresholds requiring Prevention of Significant Deterioration (PSD) review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}) and sulfuric acid mist (SAM).

Based on our review of the preliminary determination and draft permit, we have the following comments:

1. The NO_X BACT emission limit, when burning natural gas in the combustion turbines, is 10.5 ppmvd (15% oxygen). Region 4 has recently reviewed several GE 7FA dual-fuel simple cycle combustion turbine projects with a proposed BACT emissions limit of 9 ppmvd for NO_X, three of which are located in Florida (Oleander, Hardee Power, FPC-Intercession City). If the Brandy Branch facility is significantly different from these other facilities, documentation of this difference should be included in the department's final determination.

2. In condition 21 of the draft permit, the emission rate for NO_X is set as 69.3 lb/hr on a 24-hr block average as measured by CEMS. Since the proposed CTs will run in simple cycle mode and will seldom operate for 24 consecutive hours, the averaging period for this emission limit

should be much shorter, consistent with the 3-hour averaging period proposed for fuel oil combustion. Additionally, compliance with the 10.5 ppmvd limit should be demonstrated using the CEMS on the basis of a short-term average instead of with an annual stack test as stated in the draft permit. Including a short-term limit on a lb/hr basis and on a ppmvd basis will provide an emissions cap and a compliance value for any operating load.

3. Conditions 14 and 15 express the fuel usage limits in Btu/yr during any consecutive 12 months. It is unclear if this limit refers to the total Btu/yr for all turbines or for each individual turbine. The fuel usage limits should be expressed on a per combustion turbine basis. Additionally, it is unclear if the "4,000 hours during any calendar year" in Condition 13 refers to each unit or all three total. This condition should be reworded to indicate that it applies to individual turbines, and the phrase "calendar year" should be replaced with "consecutive 12 months" to be consistent with Conditions 14 and 15.

4. The cost analysis for SCR uses NO_X emissions of 12 ppm as the baseline and calculates the cost effectiveness of using SCR with controlled NO_X emissions at an assumed level of 5 ppm. In other words, the applicant does not base tons per year reduced on a specific control efficiency value. We note that the applicant's approach yields a control efficiency of about 59 percent, which is at the low end of the control efficiencies we have previously seen for SCR control.

5. In table 4-3 of the SCR cost analysis (page 4-9 of the application), the Direct Annual Costs list both a "Power Consumption" and a "Lost Power Generation" figure in the cost calculation. Although it is appropriate to calculate the cost of using additional natural gas to compensate for the power consumption resulting from pressure drops across the catalyst bed, lost revenue should not be included in the cost analysis. It is unclear in this calculation whether lost revenue was taken into account. If this is the case, the lost revenue figure should be omitted from the cost analysis.

6. In the economic analysis section of the application, an interest rate of 8% was used to calculate the cost recovery factor. This interest rate may be appropriate for the Brandy Branch Facility; however, it should be noted that the current version of the U.S. Environmental Protection Agency's (EPA's) *OAQPS Control Cost Manual* uses an interest rate of 7 percent.

7. The proposed BACT limit, found on page 8 of the draft permit, for particulate matter (PM_{10}) is 10% opacity for visible emissions. This visible emissions opacity limit is proposed as a surrogate for a BACT particulate matter emissions rate limit. It is acceptable to use the 10% opacity limit as a surrogate for monitoring and recordkeeping; however, the permit conditions also should list the corresponding emission rate for particulate matter.

8. As indicated in condition 24 and 26 of the draft permit, FDEP is proposing to allow excess emissions due to startup, shutdown or malfunction for up to 2 hours in any 24-hour period and for a 20% opacity limit of visible emissions. This proposal is inconsistent with FDEP's

preliminary determination for Kissimmee Utility's Cane Island Power Park (January 1999) which only allowed excess emissions from a simple cycle combustion turbine for 1 hour in any 24-hour period. Additionally, it is EPA's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

9. In section 5.4 (Visibility/Region Haze Analysis) of the permit application, CALPUFF modeling with ISCST3 meteorological data (CALPUFF Lite) was used to address regional haze impacts from this facility. This additional modeling was provided to the U.S. Fish and Wildlife Service (FWS) - administrator for both the Okefenokee and Wolf Island Class I areas. The modeling showed regional haze at Okefenokee significantly impacted by the project. Based on these results, JEA has agreed to shut down their Southside facility to provide air quality offsets. As requested by the FWS, CALPUFF modeling of the Southside and Brandy Branch emissions are needed to demonstrate that the proposed Brandy Branch project will not cause any additional visibility impairment at Okefenokee.

Thank you for the opportunity to comment on the Brandy Branch facility preliminary determination and draft permit. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Paul Wagner

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: NPS
NED
Duval Co.
Halpin, BAR
Holladay, BAR

File in ~~[illegible]~~ JEA Brandy Branch

Copy: Mike
Teresa
Jeff

EPA
United States
Environmental Protection
Agency

facsimile TRANSMITTAL

FAX: Bert Gianazza of JEA
Jamie Hunter of TECO

EPA Region 4
Mississippi, Tennessee, Alabama, Georgia, Florida, Kentucky, South Carolina, North Carolina

To: ~~Al Linero~~

Fax #: 850-922-6979

Subject: Brandy Branch

From: Katy Forney / Jim Little **Phone#:** 404-562-9130

Date: 9-10-99

Pages: 4, including this cover sheet.

COMMENTS:

Note To all recipients –
This gives you a pretty good idea of how EPA views some of our most recent conditions on Simple cycle projects. Be ready for similar comments on all of the rest.
Al L

EPA United States Environmental Protection Agency
Air & Radiation Technology Branch
U.S. Environmental Protection Agency
61 Forsyth Street, SW, 12th Floor
Atlanta, Georgia 30303

404-562-9105
Fax: 404-562-9095

Florida Department of Environmental Protection

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

Jeb Bush
Governor

David Struhs
Secretary

FAX TRANSMITTAL SHEET

DATE: 9-13-99

TO: ~~[illegible]~~ Bert Gianazza

PHONE:

FAX:

FROM: AL Linero

PHONE:

Division of Air Resources Management

FAX: **850.922.6979**

RE:

CC:

Total number of pages including cover sheet: 4

Message

This gives you a pretty good idea of how EPA views some of our most recent conditions on simple cycle projects. Be ready for similar comments on all of the rest.

Al Linero

If there are any problems with this fax transmittal, please call the above phone number.

"Protect, Conserve, and Manage Florida's Environmental and Natural Resources"

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

SEP 1 0 1999

4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and Draft Permit for Jacksonville Electric Authority - Brandy Branch Project (PSD-FL-267) located in Duval County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft permit dated August 11, 1999, for the above referenced facility. The preliminary determination is for the proposed construction and operation of a new electric power generating station consisting of three simple cycle combustion turbines (CTs) with a nominal generating capacity of 170 MW each. The combustion turbines proposed for the facility are General Electric (GE), frame 7FA units. Additional equipment will include the following: three 1 million gallon fuel oil storage tanks and one small diesel fire-water pump. The CTs will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. The fire-water pump will combust only diesel fuel. Each CT will be allowed to fire natural gas a maximum of 4,000 hours per year and will be allowed to fire No. 2 fuel oil a maximum of 750 hours per year. Total emissions from the proposed project are above the thresholds requiring Prevention of Significant Deterioration (PSD) review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}) and sulfuric acid mist (SAM).

Based on our review of the preliminary determination and draft permit, we have the following comments:

1. The NO_X BACT emission limit, when burning natural gas in the combustion turbines, is 10.5 ppmvd (15% oxygen). Region 4 has recently reviewed several GE 7FA dual-fuel simple cycle combustion turbine projects with a proposed BACT emissions limit of 9 ppmvd for NO_X, three of which are located in Florida (Oleander, Hardee Power, FPC-Intercession City). If the Brandy Branch facility is significantly different from these other facilities, documentation of this difference should be included in the department's final determination.

2. In condition 21 of the draft permit, the emission rate for NO_X is set as 69.3 lb/hr on a 24-hr block average as measured by CEMS. Since the proposed CTs will run in simple cycle mode and will seldom operate for 24 consecutive hours, the averaging period for this emission limit

should be much shorter, consistent with the 3-hour averaging period proposed for fuel oil combustion. Additionally, compliance with the 10.5 ppmvd limit should be demonstrated using the CEMS on the basis of a short-term average instead of with an annual stack test as stated in the draft permit. Including a short-term limit on a lb/hr basis and on a ppmvd basis will provide an emissions cap and a compliance value for any operating load.

3. Conditions 14 and 15 express the fuel usage limits in Btu/yr during any consecutive 12 months. It is unclear if this limit refers to the total Btu/yr for all turbines or for each individual turbine. The fuel usage limits should be expressed on a per combustion turbine basis. Additionally, it is unclear if the "4,000 hours during any calendar year" in Condition 13 refers to each unit or all three total. This condition should be reworded to indicate that it applies to individual turbines, and the phrase "calendar year" should be replaced with "consecutive 12 months" to be consistent with Conditions 14 and 15.

4. The cost analysis for SCR uses NO_X emissions of 12 ppm as the baseline and calculates the cost effectiveness of using SCR with controlled NO_X emissions at an assumed level of 5 ppm. In other words, the applicant does not base tons per year reduced on a specific control efficiency value. We note that the applicant's approach yields a control efficiency of about 59 percent, which is at the low end of the control efficiencies we have previously seen for SCR control.

5. In table 4-3 of the SCR cost analysis (page 4-9 of the application), the Direct Annual Costs list both a "Power Consumption" and a "Lost Power Generation" figure in the cost calculation. Although it is appropriate to calculate the cost of using additional natural gas to compensate for the power consumption resulting from pressure drops across the catalyst bed, lost revenue should not be included in the cost analysis. It is unclear in this calculation whether lost revenue was taken into account. If this is the case, the lost revenue figure should be omitted from the cost analysis.

6. In the economic analysis section of the application, an interest rate of 8% was used to calculate the cost recovery factor. This interest rate may be appropriate for the Brandy Branch Facility; however, it should be noted that the current version of the U.S. Environmental Protection Agency's (EPA's) *OAQPS Control Cost Manual* uses an interest rate of 7 percent.

7. The proposed BACT limit, found on page 8 of the draft permit, for particulate matter (PM_{10}) is 10% opacity for visible emissions. This visible emissions opacity limit is proposed as a surrogate for a BACT particulate matter emissions rate limit. It is acceptable to use the 10% opacity limit as a surrogate for monitoring and recordkeeping; however, the permit conditions also should list the corresponding emission rate for particulate matter.

8. As indicated in condition 24 and 26 of the draft permit, FDEP is proposing to allow excess emissions due to startup, shutdown or malfunction for up to 2 hours in any 24-hour period and for a 20% opacity limit of visible emissions. This proposal is inconsistent with FDEP's

preliminary determination for Kissimmee Utility's Cane Island Power Park (January 1999) which only allowed excess emissions from a simple cycle combustion turbine for 1 hour in any 24-hour period. Additionally, it is EPA's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

9. In section 5.4 (Visibility/Region Haze Analysis) of the permit application, CALPUFF modeling with ISCST3 meteorological data (CALPUFF Lite) was used to address regional haze impacts from this facility. This additional modeling was provided to the U.S. Fish and Wildlife Service (FWS) - administrator for both the Okefenokee and Wolf Island Class I areas. The modeling showed regional haze at Okefenokee significantly impacted by the project. Based on these results, JEA has agreed to shut down their Southside facility to provide air quality offsets. As requested by the FWS, CALPUFF modeling of the Southside and Brandy Branch emissions are needed to demonstrate that the proposed Brandy Branch project will not cause any additional visibility impairment at Okefenokee.

Thank you for the opportunity to comment on the Brandy Branch facility preliminary determination and draft permit. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Paul Wagner

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

RECEIVED

AUG 30 1999

BUREAU OF AIR REGULATION

FLORIDA PUBLISHING COMPANY

Publisher

JACKSONVILLE, DUVAL COUNTY, FLORIDA

STATE OF FLORIDA
COUNTY OF DUVAL

Before the undersigned authority personally appeared Steven L. Smith who on oath says that he is Legal Advertising Representative of The Florida Times-Union, a daily newspaper published at Jacksonville in Duval County, Florida; that the attached copy of advertisement, being a Legal Advertisement

in the matter of Public Notice of Intent to Issue Air Construction Permit

in the ________________ Court,

was published in THE FLORIDA TIMES-UNION in the issues of August 23, 1999

Affiant further says that the said The Florida Times-Union is a newspaper published at Jacksonville, in said Duval County, Florida, and that the said newspaper has heretofore been continuously published in said Duval County, Florida, The Florida Times-Union each day, has been entered as second class mail matter at the postoffice in Jacksonville, in said Duval County, Florida, for a period of one year next preceeding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in said newspaper.

Sworn to and subscribed before me this 25th day of August A.D. 1999.

Vera Janic Likens

Notary Public, State of Florida at Large.

My Commission Expires ....

Steven L. Smith

Vera Janic Likens
Commission # CC 547806
Expires Jun. 1, 2000
Bonded Thru
Atlantic Bonding Co., Inc.

DA 444

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 0310485-001-AC (PSD-FL-267)
JEA Brandy Branch Facility Units 1-3
Duval County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to JEA. The permit is to construct three nominal 170 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine-electrical generators with 90-foot stacks and three 1 million gallon fuel storage tanks for the proposed Brandy Branch Facility near Baldwin City, Duval County. A Best Available Control Technology (BACT) determination was required for sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), nitrogen oxides (NO_X), Sulfuric acid mist (SAM), and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are JEA, 21 West Church Street, Jacksonville, Florida 32202.

The new units will be General Electric nominal 170 MW PG7241FA combustion turbines-electrical generators. The units will operate in simple cycle mode and intermittent duty. The units will operate primarily on natural gas and will be permitted to operate no more than 4750 hours per year of which no more than 750 hours per year and 16 hours per day will be using 0.05 percent sulfur distillate fuel oil.

NO_X emissions will be controlled by Dry Low NO_X (DLN-2.6) combustors. The units must achieve the manufacturer's initial "new and clean" performance guarantee of 9 parts per million by volume at 15 percent oxygen (ppm) and meet a continuous emission limit based on 10.5 ppm. NO_X will be controlled to 42 ppm by wet injection when firing fuel oil. Sulfuric acid mist, SO_2, and PM/PM10 will be limited by use of clean fuels. Emissions of VOC and CO will be controlled by good combustion practices.

The maximum emissions in per tons per year based on the original application are summarized below. All emissions will be somewhat lower as a result of the Department's proposed BACT determination.

Pollutant	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	74.4	25/15
CO	366.2	100
NO_X	857.7	40
VOC	21	40
SO_2	124.3	40
Sulfuric Acid Mist	15.2	7

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class II significant impact levels. PSD Class I significant impact levels are exceeded for sulfur dioxide, therefore a Class I PSD increment analysis for SO_2 was conducted. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any AAQS or PSD increment.

Concurrent with the startup of the new facility, JEA will shutdown the Southside facility located at 801 Colorado Avenue in Jacksonville, Florida. The Southside emissions along with the net effect of these actions is shown below:

Pollutant	Southside Emissions	Net Emissions
PM/PM_{10}	74.9	(0.4)
CO	54.2	312
NO_X	735.5	122.2
SO_2	902.3	(778)

The Department will accept written comments and requests for a public hearing (meeting) concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of "Public Notice of Intent to Issue PSD 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 FINAL Permit, in accordance with the conditions of the DRAFT Permit, 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 DRAFT Permit issuance action for a period of 30 (thirty) days from the date of publication of this Notice. Written comments should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, mail Station #5005, Tallahassee, Florida, 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in this DRAFT Permit, the Department shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

The Department will issue FINAL Permit with the conditions of the DRAFT Permit subject to the exceptions noted above unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. The procedures for petitioning for a hearing are set forth below. Mediation is not available for the proposed action.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 850/488-9370, fax; 850/487-4938. Petitions 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. A petitioner must 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 28-5.207 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 as well as the rules and statutes which entitle the petitioner to relief; and (f) A demand for relief.

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 of intent. 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:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department Environmental Protection
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, Florida 32256-7590
Telephone: 904/448-4300
Fax: 904/448-4366

Jacksonville Regulatory and Environmental Services Department
Suite 225, 117 W. Duval Street
Jacksonville, Florida 32202
Telephone: 904/630-3484
Fax: 904/630-6338

The complete project file includes the application, technical evaluation, 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, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850-488-0114, for additional information.

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

August 30, 1999

Re: PSD-FL-267

RECEIVED
SEP 07 1999
BUREAU OF AIR REGULATION

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the visibility analysis and additional information submitted by Jacksonville Electric Authority (JEA) pertaining to its Brandy Branch project in Baldwin, Florida. As you know, in our August 3, 1999, technical review document, we expressed concern that the Brandy Branch project would significantly affect visibility in Okefenokee Wilderness, a Class I air quality area, administered by the Fish and Wildlife Service. We encouraged JEA to shut down their Southside Generating Facility, thereby offsetting potential impacts from the proposed Brandy Branch project.

We are pleased that JEA has selected this option and agree that it will result in a net benefit to air quality and visibility in Okefenokee. The technical review comments from our Air Quality Branch are enclosed.

The technical review document also summarizes our concerns regarding predicted exceedances of the Class I sulfur dioxide increments in Okefenokee. We recommend that your Department determine the causes of those exceedances and take actions to remedy them.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at (303) 969-2617.

Sincerely yours,

H Dale Hall

for Sam D. Hamilton
Regional Director

Enclosure

cc: NED
Duval Co
EPA
M. Halpin, BAR

Technical Review of Visibility Analysis and Additional Information for Jacksonville Electric Authority's Brandy Branch Generating Station Baldwin, Florida

by

Air Quality Branch, Fish and Wildlife Service – Denver

August 11, 1999

PSD-FL-267

We have reviewed the visibility analysis and additional information supplied to us regarding Jacksonville Electric Authority (JEA)'s proposed Brandy Branch Project, 34 km southeast of Okefenokee Wilderness. Our August 3, 1999, technical review document summarized our concerns for potential impacts from this project to air quality related values, specifically visibility, in Okefenokee. At that time, we noted that JEA should consider several options to mitigate potential visibility impacts, including shutting down their Southside Generating Station and using the subsequent emissions decrease to offset the new emissions expected at the Brandy Branch Station. We supported this option, as it would result in a high-emitting, poorly controlled, and inefficient facility (fueled by oil) being replaced by a lower-emitting, rigorously controlled, and more efficient facility (fueled primarily by natural gas, with oil as back-up).

We understand that JEA has selected this option and will accept as a permit condition for Brandy Branch the shutdown of Southside. We also understand that the Florida Department of Environmental Protection (FDEP) supports this alternative. In addition, JEA has demonstrated that this option will result in a net benefit to air quality and visibility at Okefenokee. JEA performed a CALPUFF-Lite modeling analysis that predicted that the Southside Station causes an 84% change in light extinction (a measure of visibility impairment) at Okefenokee; the proposed Brandy Branch facility would cause a 5% change in light extinction while burning natural gas, and a 20% change in light extinction while burning oil. Shutting down Southside will therefore result in a net benefit to visibility, while allowing electrical generation to continue.

We have also reviewed the Class I increment analysis for the proposed project. The ISCST3 analysis predicted that Brandy Branch emissions would contribute significantly to consumption of the 3-hour and 24-hour sulfur dioxide (SO_2) Class I increments. As required by FDEP, JEA then performed a cumulative analysis, modeling all increment-consuming sources in the area. The cumulative analysis predicted exceedances of both the 3-hour and 24-hour SO_2 Class I increments. Brandy Branch, however, did not contribute significantly to increment consumption on the days of the exceedances. We recommend that FDEP determine which sources are contributing significantly to the exceedances and take actions to remedy the exceedances.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

INTERοFFICE MEMORANDUM

Date: 27-Aug-1999 02:34pm
From: Gianazza, N. Bert
GianNB@jea.com
Dept:
Tel No:

To: 'Mike Halpin' (Halpin_M@dep.state.fl.us)
CC: 'Alvaro Linero TAL 850/921-9532' (Alvaro.Linero@dep.state.fl.us)
CC: 'Clair Fancy' (clair.fancy@dep.state.fl.us)
CC: 'Bareta, Mark J.' (BaretaMJ@bv.com)
CC: 'ROBERT A MANNING' (ROBERTM@HGSS.COM)

Subject: Comments on Draft Brandy Branch PSD permit

Mike, below please find our comments on the Brandy Branch draft permit. I avoided using over-strikes since they seem to cause a problem for my email. I can clarify any comments by phone.

I need to resolve these issues before the expiration of the 30-day comment period (9/20) so we can get the permit by 10/1. Engineering allowed a whole week of float in their very aggressive construction schedule (in order to meet anticipated peak demand) and I don't want to be the one to use it up.

Since we didn't have any comments on the last three permitting exercises we went through this year, I don't expect outside comments to be submitted on this project either.

Even if you don't agree with our position on some of the below comments, I'm sure we can reach a mutually satisfactory agreement that gets you what you need with the least impact necessary on operations.

If you would like to talk to me and I'm not in my office, please use my beeper number (904-818-6247). As long as I'm in town I'll call you right away. Perhaps we can resolve most of the issues prior to our meeting on 9/15.

Thanks, Bert

Technical Evaluation and Preliminary Determination

1. Page TE-3. The Project Description lists VOCs as a pollutant for which a significant emission increase occurs and therefore requires a BACT determination. This is incorrect because of the VOC emission limits requested by JEA, and imposed pursuant to this permit. The BACT itself, on page BD-10, confirms this fact. The Project Description should be revised accordingly.

2. Page TE-3. The Project Description discusses the "maximum heat input rating" in terms of the higher heating value (HHV) of the fuel, whereas Specific Condition 8 references the capacity of the unit in terms of the lower heating value (LHV) of the fuel. The Project Description should be revised accordingly to reference heat input in terms of the LHV.

3. Page TE-4. The Project Description's discussion of the limit on hours of operation should be revised. We request 4750 hours per unit per year of which 750 per unit can be on oil. All modeling was performed using 4800 hours of operation of which 800 hours was on oil with no significant visibility or PSD impacts. This does not include the improvements in environmental impacts as a result of decommissioning Southside Generating Station. Specific Condition 13 should be revised accordingly.

4. Page TE-5. The discussion of the Process Description states that an evaporative inlet cooler (fogger) "can" be installed. JEA requests that this possibility be reflected in the permit itself.

5. Page TE-6. The Rule Applicability analysis incorrectly references 40 CFR 52.21 and 40 CFR 52. These provisions only apply to states that do not have an approved PSD program, which Florida does. 40 CFR 51.166 lists the requirements for a state to obtain an approved program.

6. Page TE-7. The Control Technology section references VOCs as a pollutant for which the PSD regulations are applicable in the context of the Brandy Branch project. As explained above, this reference is incorrect and should be deleted.

Air Construction Permit

7. Page 4 of 14. Conditions 6 and 7. These conditions should be deleted because, as explained above, 40 CFR 52.21 is not applicable to facilities in Florida, and further, the 18 month limitation on commencing construction and the provisions on phased construction projects are not contained in Florida's approved PSD program. Thus, there is no basis for requiring this type of continual review; if air permitting requirements are triggered in the future, they should be applied at that time.

8. Page 6 of 14. Condition 7. For clarification in the first sentence, JEA requests that parentheses be placed around the words "No. 2 or superior grade of distillate fuel oil."

9. Page 7 of 14. Condition 8. In accordance with the Department's position on recently issued Title V permits, JEA requests that a permitting note be placed at the end of Condition 8 to clarify that the heat input values are included only for purposes of determining capacity during testing, and that regular record keeping is not required.

10. Page 7 of 14. Condition 13. For clarification, the first word of this Condition should be changed from "The" to "Each." Also, the hours should be revised to reflect the correct numbers. We request 4750 in accordance with the no significant impact analyses performed.

11. Page 7 of 14. Conditions 14 and 15. These conditions should be deleted because (a) the permit already imposes sufficient limitations on capacity through the hourly limitation (Condition 13) and the maximum heat input rate for purposes of determining capacity during testing (Condition 8), and (b) other recently issued PSD permits in Florida do not contain this type of redundant limitation.

12. Page 8 of 14. Condition 17. This Condition should be deleted. There is no reason to believe that JEA will be unable to meet its permit limits. If this were to occur at some point in the future, however, then appropriate actions could be taken at that time.

13. Page 8 of 14. Condition 20. To accurately reflect the purpose and basis for the chart at the bottom of page 8 (i.e., a BACT analysis was not required for VOC), the first sentence should be revised as follows: "The following table is a summary of the emission limits for the combustion turbines and is followed by the applicable specific conditions."

14. Page 9 of 14. Condition 21, fourth bullet. This Condition unnecessarily extends the determination of BACT when firing oil and should be deleted. Alternatively, instead of requiring a report within 18 months of the initial compliance test, it would be more appropriate to require such a test after a certain number of hours of operating on oil. These units may not burn oil, regularly or even at all, and would therefore be unable to evaluate a NOx rate that can "consistently be achieved" until such time as they operate a certain number of hours on oil. Accordingly, if this Condition is not deleted, JEA requests that the beginning of the first sentence be revised as follows: "Whithin 18 months after the initial compliance test and after burning at least 400 hours on oil, the permittee shall prepare . . . ."

15. Page 9 of 14. Condition 22. The last sentence should clarify that the test method for determining compliance with the lb/hr emissions is EPA Method 10.

16. Page 9 of 14. Condition 25. The last sentence should clarify that the test method for determining compliance with the lb/hr emissions is EPA Method 18 and/or 25A.

17. Page 10 of 14. Condition 26. The last sentence appears to have a typographical error. Please add the word "caused" after the words "Excess emissions."

18. Page 10 of 14. Condition 27. To accurately reflect the regulatory requirement under Rule 62-210.700(6), Fla. Admin. Code, the following revision should be made to the first sentence: "If excess emissions occur due to malfunction, the owner or operator . . . ." Also, this Condition should only require JEA to notify RESD, and not also DEP, because RESD is the compliance authority. Other conditions in this permit require similar duplicate reporting and should be revised accordingly.

19. Page 10 of 14. Condition 29. To clarify our understanding that initial testing when burning oil is not required until the unit actually begins firing oil, as well as other changes, JEA requests the following revisions: "Initial (I) performance tests shall be performed on each unit while firing natural gas as well as while firing fuel oil, in accordance with Condition 28. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) to air pollution control equipment, including low NOx burners."

20. Page 11 of 14. Condition 30. The references to SCR controls is unnecessary and inappropriate and should therefore be deleted. Also, JEA requests a revision to accurately reflect the regulatory provisions regarding the calculation of emission rates, as follows: "Continuous compliance with the NOx emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hour block average (while burning gas) or a 3-hr average (while burning oil). For the 24-hr block average (lb/hr) emission may be determined via EPA Method 19 or equivalent EPA approved methods. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or a 3-hr period where applicable) and a new average emission rate is calculated from

the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr. period where applicable). Valid hourly emission rates . . . ."

21. Page 11 of 14. Condition 31. For clarification and to be consistent with recently issued PSD permits, JEA requests the following revisions: " . . . for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. . . ."

22. Page 11 of 14. Condition 33. The reference to BACT should be deleted because VOCs were not subject to a BACT determination for this facility.

23. Page 12 of 14. Condition 40. This Condition should be revised, in accordance with the comments regarding Conditions 14 and 15 above. Specifically, paragraphs (1) and (2) should be deleted in their entirety, and the words "as heat input" should be deleted from paragraphs (3) and (5).

24. Page 13 of 14. Condition 41. The last sentence is redundant to other permit conditions and therefore should be deleted. At a minimum, the words "and fuel switching" should be deleted because this is not required by regulation.

25. Page 13 of 14. Condition 43. For clarification and to be consistent with other recently issued PSD permits, the last sentence should be revised as follows: "Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Northeast District Office as well as RESD for review. no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62."

26. Page 13 of 14. Condition 45, first bullet. For clarification, this Condition should be revised as follows: "The permittee shall apply for an Acid Rain permit in compliance with the deadlines specified in 40 CFR 72.30."

RFC-822-headers:
Received: from epic5.dep.state.fl.us ([199.73.143.30])
by mail.epic1.dep.state.fl.us (PMDF V5.2-32 #37976)
with ESMTP id <01JF9KCUY7JG000FIB@mail.epic1.dep.state.fl.us>; Fri,
27 Aug 1999 14:32:26 EDT
Received: from es2.jea.com ([161.243.208.42]) by mail.epic5.dep.state.fl.us
(PMDF V5.2-32 #31508)
with ESMTP id <01JF9KFLPL1M0003FS@mail.epic5.dep.state.fl.us>; Fri,
27 Aug 1999 14:34:40 -0400 (EDT)
Received: by es2.jea.com with Internet Mail Service (5.5.2448.0)
id <PFGRPF09>; Fri, 27 Aug 1999 14:34:23 -0400
X-Mailer: Internet Mail Service (5.5.2448.0)

RECEIVED
AUG 27 1999
BUREAU OF AIR REGULATION

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

OGC CASE NO.:
FDEP File No.: 0310485-001AC (PSD-FL-267)

JEA
Brandy Branch Facility
Duval County, Florida

______________________________/

REQUEST FOR ENLARGMENT OF TIME

By and through undersigned counsel, JEA (formerly known as the Jacksonville Electric Authority) hereby requests, pursuant to Florida Administrative Code Rule 62-110.106(4), an enlargement of time, to and including October 1, 1999, in which to file a Petition for Administrative Proceedings in the above-styled matter. As good cause for granting this request, JEA states the following:

1. The Department of Environmental Protection (Department) issued an "Intent to Issue Air Construction Permit" (FDEP File No.: 0310485-001-AC (PSD-FL-267)) for the JEA Brandy Branch facility located in Duval County, Florida, dated August 11, 1999. Along with the Intent to Issue, the Department issued a Draft Air Construction Permit and "Public Notice of Intent to Issue Air Construction Permit."

2. JEA received an unsigned version of this Intent to Issue by e-mail on August 12, 1999.

3. Based on JEA's review, the Draft Permit and associated documents contain several provisions that warrant clarification or correction.

4. This request is filed simply as a protective measure to avoid waiver of JEA's right to challenge certain conditions contained in the Draft Permit. Grant of this request will not prejudice either party, but will further their mutual interest and hopefully avoid the need to file a petition and proceed to a formal administrative hearing. If the Department denies this request, JEA requests the opportunity to file a Petition for Administrative Proceeding within 10 days of such denial.

WHEREFORE, JEA respectfully requests that the time for filing of a Petition for Administrative Proceedings in regard to the Department's Intent to Issue Air Construction Permit for FDEP File No.: 0310485-001-AC (PSD-FL-267) be formally extended to and including October 1, 1999.

Respectfully submitted this 26 day of August, 1999

HOPPING GREEN SAMS & SMITH, P.A.

By: Robert A. Manning

Robert A. Manning
Florida Bar No. 0035173
Post Office Box 6526
Tallahassee, FL 32314
(850) 222-7500

ATTORNEYS FOR JEA

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 26 day of August, 1999:

Al Linero
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Scott Goorland, Esq.
Department of Environmental Protection
Room 669
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Clair Fancy
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Robert A. Manning
Attorney

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

August 12, 1999

RECEIVED
AUG 17 1999
BUREAU OF AIR REGULATION

Re: PSD-FL-267

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the additional information submitted by Jacksonville Electric Authority (JEA) pertaining to its Brandy Branch project in Baldwin, Florida. The project is located 34 km southeast of Okefenokee Wilderness and 127 km southwest of Wolf Island Wilderness, both Class I air quality areas, administered by the U.S. Fish and Wildlife Service (FWS). The technical review comments from our Air Quality Branch are enclosed. In summary, JEA's regional haze analysis predicts that the project will significantly contribute to visibility impairment in Okefenokee. Based on this information, FWS would object to the issuance of a permit for the project. The technical review document summarizes the options available to JEA, including choosing not to proceed with the project, reducing the project's emissions, offsetting the project's emissions with the shutdown of JEA's Southside Station, and conducting a more refined modeling analysis. In any case, JEA must demonstrate that the Brandy Branch project will not further reduce visibility in the Okefenokee Class I area.

Thank you for the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have any questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at (303)969-2617.

Sincerely yours,

H Dale Hall
for Sam D. Hamilton
Regional Director

cc: M. Halpin, BAR
Duval Co.
NED
EPA
C. Holladay, BAR

Enclosure

B. Gianazza, JEA
A. Compaan, B+V

Technical Review of Additional Information
for Jacksonville Electric Authority's Brandy Branch Generating Station
Baldwin, Florida
by
Air Quality Branch, Fish and Wildlife Service – Denver
August 3, 1999

PSD-FL-267

Jacksonville Electric Authority (JEA) is proposing to install three 170 MW simple cycle combustion turbines at their Brandy Branch Facility. The turbines will fire natural gas as the primary fuel, with low sulfur (less than 0.05 %) fuel oil as a back-up fuel. The Brandy Branch Facility is located 34 km southeast of Okefenokee Wilderness and 127 km southwest of Wolf Island Wilderness, both Class I air quality areas administered by the U.S. Fish and Wildlife Service (FWS). The project will result in PSD-significant increases in emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM), fine particulate matter less than 10 microns in diameter (PM-10), carbon monoxide (CO), and sulfuric acid mist (SAM). Proposed emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	858
SO_2	124
PM-10	75
CO	366
SAM	15.2

Air Quality Related Values (AQRV) Analysis

JEA performed a regional haze analysis for Wolf Island, concluding that the project would not contribute significantly to visibility impairment in the area. In December 1998, we advised JEA that they should also evaluate regional haze impacts in Okefenokee. Regional haze analyses are required of sources greater than 50 km from a receptor in a Class I area. Although the project was only 34 km from the nearest boundary of the Class I area, the project was more than 50 km from some receptors in the Class I area. (Okefenokee is approximately 55 km from south to north.)

An Industrial Source Complex (ISC) modeling analysis by JEA indicated that the project had the potential to significantly contribute to regional haze at Okefenokee. On June 9, 1999, we advised the applicant, via phone, that they had several options, including reducing production, accepting lower emissions limits, or performing a refined modeling analysis (CALPUFF-Lite or CALPUFF). In any case, they needed to demonstrate that the project's emissions would not significantly contribute to visibility impairment in the Class I area.

The applicant chose to do an analysis with CALPUFF-Lite (a screening version of CALPUFF) and submitted the results June 24, 1999. Although this model predicted impacts lower than impacts predicted with ISC, they were still significant. The change in visibility (light extinction) while burning gas was predicted to be 5.6%. The change in visibility (light extinction) while burning fuel oil was predicted to be 27.2%. FWS considers a change of greater than 5% to be significant and a potential adverse impact to the Class I area. At this time we reiterated JEA's options (see above). JEA stated its intention of doing a CALPUFF analysis, a refined version of CALPUFF-Lite.

On July 19, 1999, in a phone conversation with JEA, we learned that they had not yet started the CALPUFF analysis. However, JEA requested that the Florida Department of Environmental Protection issue an intent to permit the project on August 15. We advised JEA that, if they do not demonstrate by that time that the project's emissions would not significantly contribute to regional haze, we would object to the project. JEA agreed to start the CALPUFF analysis immediately. In addition, JEA agreed to accept as a permit condition the shut-down of their Southside Generating Station, 15 km south of Brandy Branch. JEA believes that the Southside shut-down would result in an emissions decrease that would more than offset new emission impacts from Brandy Branch. We stated our support of the shut-down, as it would result in a high-emitting facility being replaced by a more efficient and lower-emitting facility. We noted that such offsets should result in a net benefit to air quality at the Class I area, and that this should be demonstrated by modeling.

In summary, JEA must demonstrate to us that the proposed Brandy Branch project will not cause additional visibility impairment at Okefenokee Wilderness. JEA has a variety of options for doing this, including choosing not to proceed with the project, reducing the project's emissions, offsetting the project's emissions with the shut-down of Southside Station, and conducting a more refined modeling analysis. If refined modeling still predicts a significant contribution to visibility impairment from the project, FWS will consider the magnitude, duration, and frequency of impacts, and other factors in making an adverse impact determination.

Contact: Ms. Ellen Porter, Air Quality Branch (303)969-2617.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

August 11, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Walter P. Bussels, Managing Director and CEO
Jacksonville Electric Authority
Brandy Branch Facility
21 West Church Street
Jacksonville, Florida 32202-3139

Re: DEP File No. 0310485-001-AC (PSD-FL-267)
Brandy Branch Facility
Three 170 Megawatt Combustion Turbines

Dear Mr. Bussells:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the Brandy Branch Facility to be located near Baldwin City Duval County. The Department's Intent to Issue PSD Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time 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 A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9530.

Sincerely,

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/mph

Enclosures

In the Matter of an
Application for Permit by:

Mr. Walter P. Bussells, Managing Director and CEO
JEA
21 West Church Street
Jacksonville, FL 32202

DEP File No. 0310485-001-AC (PSD-267)
Brandy Branch Facility, Units 1 –3
Duval 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 attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, JEA, applied on May 18, 1999 to the Department for an air construction permit to construct three 170-MW dual-fuel "F" class combustion turbines and three 1 million gallon fuel oil storage tanks for the Brandy Branch facility, located approximately 1 mile northeast of Baldwin City, Duval 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 under the provisions for the Prevention of Significant Deterioration (PSD) of Air Quality is required for the proposed work.

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 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 62-103.150, 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 within 30 (thirty) days in the legal advertisement section of a newspaper of general circulation in the area affected. 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. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. 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) within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit pursuant to Rule 62-103.150 (6), F.A.C.

The Department will issue the FINAL Permit, in accordance with the conditions of the enclosed DRAFT Permit 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 a public hearing (meeting) concerning the proposed DRAFT Permit issuance action for a period of 30 (thirty) days from the date of publication of "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT." Written comments and requests for a public meeting should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the Department shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

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, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8-12-99 to the person(s) listed:

Walter P. Bussells, JEA *
N. Bert Gianazza, P.E., JEA
Gregg Worley, EPA
John Bunyak, NPS
Chris Kirts, NED
James L. Manning, P.E. RESD
Anthony L. Compaan, Black & Veatch

Clerk Stamp

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

Kim Tober 8-12-99
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0310485-001-AC (PSD-FL-267)

JEA Brandy Branch Facility – Units 1-3
Duval County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to JEA. The permit is to construct three nominal 170 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine-electrical generators with 90-foot stacks and three 1 million gallon fuel oil storage tanks for the proposed Brandy Branch Facility near Baldwin City, Duval County. A Best Available Control Technology (BACT) determination was required for sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), sulfuric acid mist (SAM), and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are JEA, 21 West Church Street, Jacksonville, Florida 32202.

The new units will be General Electric nominal 170 MW PG7241FA combustion turbines-electrical generators. The units will operate in simple cycle mode and intermittent duty. The units will operate primarily on natural gas and will be permitted to operate 4000 hours per year of which no more than 750 hours per year and 16 hours per day will be using 0.05 percent sulfur distillate fuel oil.

NO_X emissions will be controlled by Dry Low NO_X (DLN-2.6) combustors. The units must achieve the manufacturer's initial "new and clean" performance guarantee of 9 parts per million by volume at 15 percent oxygen (ppm) and meet a continuous emission limit based on 10.5 ppm. NO_X will be controlled to 42 ppm by wet injection when firing fuel oil. Sulfuric acid mist, SO_2, and PM/PM_{10} will be limited by use of clean fuels. Emissions of VOC and CO will be controlled by good combustion practices.

The maximum emissions in tons per year based on the original application are summarized below. All emissions will be somewhat lower as a result of the Department's proposed BACT determination.

Pollutant	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	74.4	25/15
CO	366.2	100
NO_X	857.7	40
VOC	21	40
SO_2	124.3	40
Sulfuric Acid Mist	15.2	7

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class II significant impact levels. PSD Class I significant impact levels are exceeded for sulfur dioxide, therefore a Class I PSD increment analysis for SO_2 was conducted. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any AAQS or PSD increment.

Concurrent with the startup of the new facility, JEA will shutdown the Southside facility located at 801 Colorado Avenue in Jacksonville, Florida. The Southside emissions along with the net effect of these actions is shown below:

Pollutant	Southside Emissions	Net Emissions
PM/PM_{10}	74.9	(0.4)
CO	54.2	312
NO_X	735.5	122.2
SO_2	902.3	(778)

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

The Department will issue FINAL Permit with the conditions of the DRAFT Permit subject to the exceptions noted above unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. The procedures for petitioning for a hearing are set forth below. Mediation is not available for the proposed action.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 850/488-9370, fax: 850/487-4938. Petitions 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. A petitioner must 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 28-5.207 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, as well as the rules and statutes which entitle the petitioner to relief; and (f) A demand for relief.

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 of intent. 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:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department Environmental Protection
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, Florida 32256-7590
Telephone: 904/448-4300
Fax: 904/448-4366

Jacksonville Regulatory and Environmental Services Department
Suite 225, 117 W. Duval Street
Jacksonville, Florida 32202
Telephone: 904/630-3484
Fax: 904-630-6338

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, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

JEA Brandy Branch Facility Units 1 - 6

Three 170 Megawatt Combustion Turbines
Three 1 Million Gallon Fuel Oil Storage Tanks
Baldwin City, Duval County

DEP File No. 0310485-001-AC (PSD-FL-267)

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

August 11, 1999

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

JEA (formerly Jacksonville Electric Authority)
21 West Church Street
Jacksonville, FL 32202

Authorized Representative: *Mr. Walter P. Bussells, Managing Director and CEO*

1.2 Reviewing and Process Schedule

05-18-99:	Date of Receipt of Application
05-24-98:	DEP Incompleteness Letter
06-22-99:	Received JEA Response to Incompleteness Letter
07-21-99:	DEP Second Incompleteness Letter
08-05-99:	Received JEA Response to Incompleteness Letter
08-11-99:	Intent Issued

2. FACILITY INFORMATION

2.1 Facility Location

The JEA Brandy Branch Facility will be located approximately 1 mile northeast of Baldwin City, Duval County (See Figure 1). This site is approximately 34 kilometers southeast and 127 kilometers southwest of the Okefenokee and Wolf Island Class I National Wilderness Areas, respectively. UTM coordinates for this facility are Zone 17; 408.81 km E; 3354.38 km N.

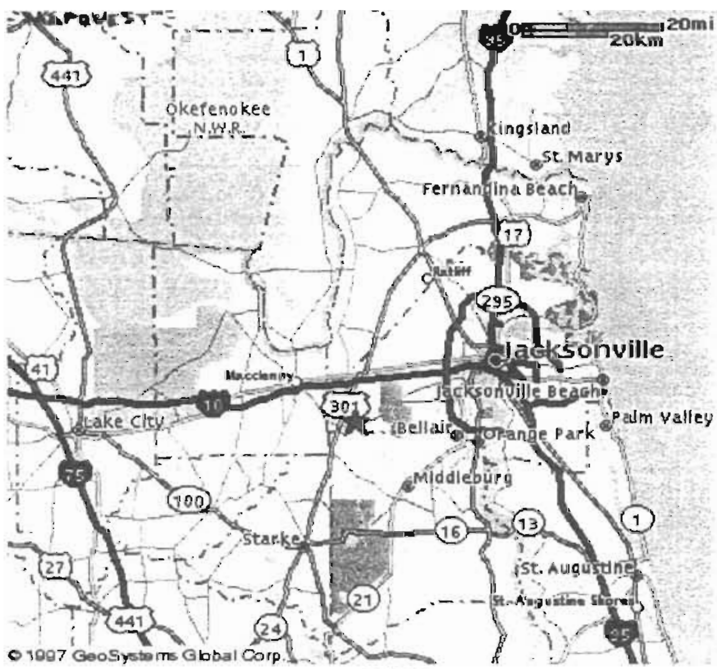


FIGURE 1

2.2 Standard Industrial Classification Codes (SIC)

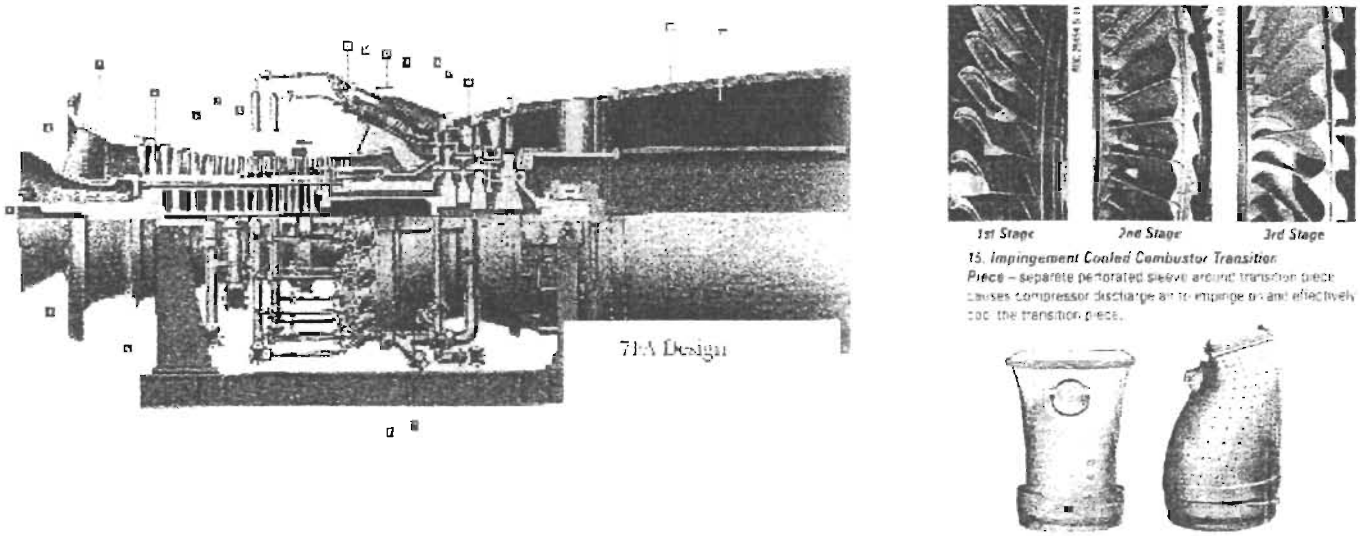
Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

mmBtu/hr higher heating value (HHV) at 20°F while operating at 100% load. The main fuel will be natural gas and the units are proposed by JEA to operate up to 4,000 hours per year on natural gas and 800 hours per year (16 hours per day maximum) on fuel oil.

JEA proposes to shutdown its Southside Station upon startup of the Brandy Branch facility, resulting in a net reduction of regulated pollutant emissions. This is further discussed in Section 6.

The key components of the GE MS 7001FA (a predecessor of the PG 7241FA) are identified in Figure 2 below. An exterior view is shown in Figure 3. Each unit will be delivered with 14 can-annular design, DLN-2.6 combustors instead of the earlier-generation combustors supplied with the MS7001FA.

FIGURE 2



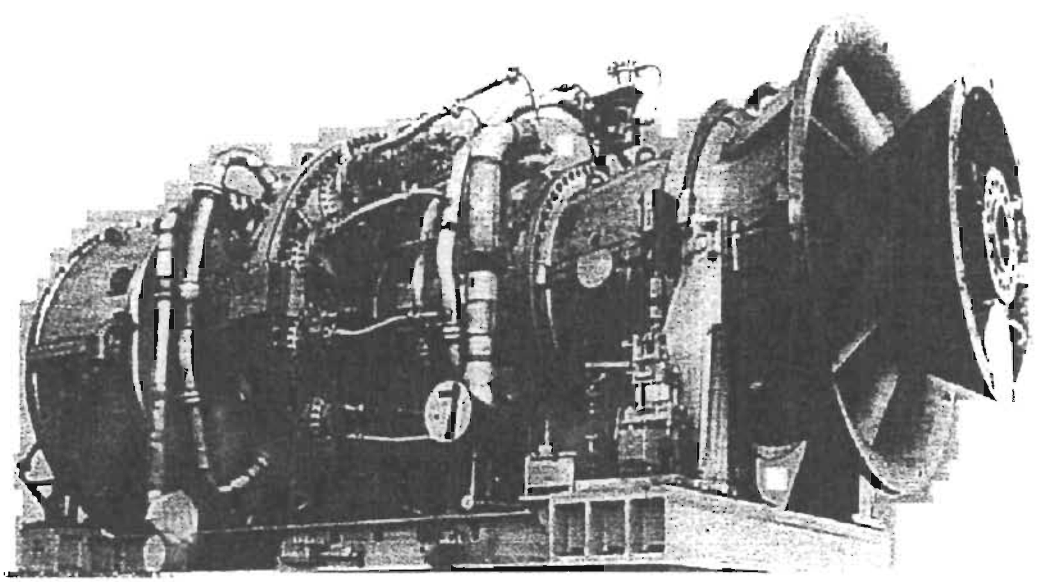


FIGURE 3

2.3 Facility Category

This proposed facility will generate 510 megawatts (nominal MW) of electrical power. The 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 (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY.

This facility is not 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 250 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD), and a Best Available control Technology determination is required. Given that emissions of at least one single criteria pollutant will exceed 250 TPY, PSD Review and a BACT determination are required for each pollutant emitted in excess of the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. These values are: 40 TPY for NO_X, SO_2, and VOC; 25/15 TPY of PM/PM_{10}; 7 TPY of Sulfuric Acid Mist (SAM); and 100 TPY of CO.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
005	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
006	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank

JEA proposes to construct three nominal 170 MW General Electric PG7241FA simple cycle, intermittent duty combustion turbine-electrical-generators with 90-foot stacks and three 1 million gallon fuel oil storage tanks at the planned Brandy Branch Facility.

According to the application, the facility will emit approximately 856.8 tons per year (TPY) of NO_X, 366 TPY of CO, 74.4 TPY of PM/PM10, 124.3 TPY of SO_2, 20.4 TPY of VOC, and 15 TPY of SAM.

Significant emission rate increases per Table 212.400-2, F.A.C. will occur for carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (SAM), particulate matter (PM/PM_{10}), volatile organic compounds (VOC) and nitrogen oxides (NO_X). A BACT determination is required for each of these pollutants. An air quality impact review is also required for CO, PM/PM_{10}, NO_X, and SO_2.

Each turbine will be equipped with Dry Low NO_X (DLN-2.6) combustors for the control of NO_X emissions to 9 - 10.5 ppmvd at 15% O_2 from 50% load up to 100% load conditions during normal operations. Each turbine will have a maximum heat input rating of 1,736 (gas) and 1,935 (oil)

4. PROCESS DESCRIPTION

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines. Project specific information is interspersed where appropriate.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2400 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

In the JEA project, the units will operate as peaking units in the simple cycle mode. Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is approximately 35 percent for F-Class combustion turbines in the simple cycle mode. In addition to shaft energy output, 1 to 2 percent of fuel input energy can be attributed to mechanical losses. The balance is exhausted from the turbine in the form of heat.

In combined cycle projects, the gas turbine drives an electric generator while the exhausted gases are used to raise additional steam in a heat recovery steam generator. The steam, in-turn, drives another electrical generator producing another 80-90 MW. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures), an evaporative inlet cooler (fogger) can be installed ahead of the combustion turbine inlet. At an ambient temperature of 95 °F, roughly 7-14 MW of power can be regained per unit by using the foggers.

Additional process information related to the combustor design, and control measures to minimize pollutant emissions are given in the draft BACT determination distributed with this evaluation.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility will be located in Duval County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) for the reasons given in Section 2.3, Facility Category, above

This PSD review consists of an evaluation of resulting ambient air pollutant concentrations, and increases with respect to the National Ambient Air Quality Standards and Increments as well as a determination of Best Available Control Technology (BACT) for PM/PM_{10}, VOC, CO, SAM and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth

The emission units affected by this PSD permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

5.1 State Regulations

Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 60	Applicable sections of Subpart A, General Requirements, NSPS Subparts GG and Kb
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)
40 CFR 52	Prevention of Significant Deterioration of Air Quality (applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed Units 1-3 will emit the following PSD pollutants (Table 212.400-2, F.A.C.): PM/PM_{10}, SO_2, NO_X, CO, SAM, and negligible quantities of fluorides (F), mercury (Hg) and lead (Pb). The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for Units 1-3 are summarized in the Draft BACT document and Specific Condition Nos. 20-25 of Draft Permit PSD-FL-267.

6.2 Emission Summary

The annual emissions increases for all PSD pollutants as a result of the project are presented below:

PROJECT EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutant	Gas Firing[1]	Oil Firing[1]	Total[1]	PSD Significance	PSD REVIEW?
PM/PM_{10}	54	20	74.4	25	Yes
SO_2	6	118	124.3	40	Yes
NO_X	475	382	857.7	40	Yes
CO	288	78	366.2	100	Yes
Ozone(VOC)	17	4	21	40	No
Sulfuric Acid Mist			15.2	7	Yes
Total Fluorides	<<3	<<3	<<3	3	No
Mercury	<<0.1	<<0.1	<0.1	0.1	No
Lead	<<0.6	<<0.6	<0.6	0.6	No

1. Based on 4000 hours of gas firing and 800 hours of fuel oil firing. Reference ambient temperature is 59 °F.

The annual reductions for major PSD pollutants as a result of the Southside Station shutdown are:

SOUTHSIDE EMISSIONS (TPY) AND OVERALL NET IMPACT

Pollutant	Tons per Year[2]	Net Emission Changes (TPY)
PM/PM_{10}	74.9	(0.4)
SO_2	902.3	(778)
NO_X	735.5	122.2
CO	54.2	312

2. Based on data submitted by JEA for the operation of the Southside Station for the years of 1997 and 1998.

On balance, there will be a net reduction of regulated pollutants emitted in Duval County as a result of this project, with the largest reductions being SO_2 emissions.

6.3 Control Technology

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may be potentially emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_X, SO_2, CO, SAM, VOC and PM/PM_{10}. Emissions control will be accomplished primarily by good combustion of clean natural gas and the limited use of low sulfur (0.05 percent) distillate fuel oil. The combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. A full discussion is given in the Draft Best Available Control

Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Introduction

The proposed project (absent the Southside Station shutdown) will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM_{10}, CO, NO_X, SO_2, and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. There are no applicable PSD increments or AAQS for SAM.

The applicant's initial PM_{10}, CO, and NO_X air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. However, the initial SO_2 analysis showed a significant impact in a Class I area; therefore, a Class I PSD increment analysis for SO_2 was conducted. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for PM_{10}, CO, SO_2, and NO_X;
- A Class I PSD increment analysis for SO_2;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

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

6.4.2 Models and Meteorological Data Used in the Significant Impact Analysis

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. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Jacksonville, Florida (surface data) and Waycross, Georgia (upper air data). The 5-year period of meteorological data was from 1984 through 1988. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

For determining the project's significant impact area in the vicinity of the facility and if there are significant impacts from the project on any PSD Class I area, the highest predicted short-term concentrations and highest predicted annual averages were compared to their respective significant impact levels.

6.4.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst-case load conditions the ISCST3 model was used to evaluate dispersion of emissions from the simple cycle facility for three loads (50%, 75%, and 100%) using worst case or "enveloped" stack parameters. If this modeling at worst-case load conditions shows significant impacts, additional multi-source modeling is required to determine the project's impacts on the existing air quality and any applicable AAQS and PSD increments. Receptors were placed along the fence line of the facility at 50-meter intervals. They were also placed in the Okefenokee National Wilderness Area (ONWA), and the Wolf Island National Wilderness Area (WINWA), which are the closest PSD Class I areas. ONWA and WINWA are located approximately 34 km southeast and 127 km southwest of the project respectively. The receptor grid for predicting maximum concentrations in the vicinity of the project was a Cartesian receptor grid that contained close field, near field, mid field, and far field receptors with dimensions centered on the simple-cycle facility stacks. The inner portion of the grid had receptors at 100 m spacing out to 2,000 m. A 250 m spacing was used out to 5,000 m; a 500 m spacing was used out to 7,000 m; and a 1,000 m spacing was used out to 10,000 m. For predicting impacts at the PSD Class I areas, ten discrete receptors and one discrete receptor were placed along the borders of the ONWA and WINWA, respectively. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this preliminary modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility or in the Class I areas. The tables below show the results of this modeling.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.04	1	NO
	24-hour	4.18	5	NO
CO	8-hour	4.64	500	NO
	1-hour	10.78	2000	NO
NO_x	Annual	0.58	1	NO
SO_2	Annual	0.04	1	NO
	24-hour	4.22	5	NO
	3-hour	14.88	25	NO

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (ONWA AND WINWA)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)		Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?	
		ONWA	WINWA		ONWA	WINWA
PM_{10}	Annual	0.002	0.001	0.2	NO	NO
	24-hour	0.090	0.040	0.3	NO	NO
NO_2	Annual	0.010	0.005	0.1	NO	NO
SO_2	Annual	0.002	0.001	0.1	NO	NO
	24-hour	0.236	0.110	0.2	YES	NO
	3-hour	1.381	0.762	1	YES	NO

The results of the significant impact modeling show that there are no significant impacts predicted due to the emissions from this project in the Class II area. However, the maximum predicted air quality impact due to SO_2 emissions is greater than the significant impact levels in the ONWA Class I area for the 24-hour and 3-hour averaging periods. Therefore, the applicant was required to conduct full impact SO_2 modeling in the ONWA Class I area. Full impact modeling is modeling that considers not only the impact of the project but the impacts of the existing facility and other major sources located within the vicinity of the project and the Class I areas. No further modeling of any other pollutants were required.

6.4.4 PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant. Atmospheric dispersion modeling, as previously described, was performed to quantify the amount of PSD increment consumed in the ONWA Class I area. The results of this analysis are shown in the tables below. Maximum SO_2 concentrations predicted for the proposed project at receptors in the ONWA show impacts greater than the PSD Class I increments for the 3-hour and 24-hour averaging times on numerous occasions. In order to assess the proposed project's contribution to any predicted ONWA Class I exceedances, an analysis was performed to determine all time periods and receptors at which an exceedance was predicted to occur. For each case, the proposed modification's impact was determined and compared to the EPA recommended significance levels of 1 ug/m^3 and 0.2 ug/m^3 for the 3-hour and 24-hour averaging times, respectively. The impact of the proposed project was always less than these significance levels at any receptor and for any time period when there were predicted exceedances or violations of increments. Therefore, the proposed modification will not contribute significantly to any predicted exceedance or violation of Class I increments and may be permitted by Department rules.

PSD CLASS I INCREMENT ANALYSIS (ONWA)

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Impact Greater Than Allowable Increment?	Allowable Increment (ug/m^3)	Maximum Project Contribution To Any Exceedance	EPA Significant Impact Level	Project Contribution Significant?
SO_2	24-hr	7.1	YES	5.0	0.100	0.2	NO
	3-hr	28.7	YES	25.0	0.00032	1.0	NO

6.4.5 Impacts Analysis

Impact Analysis Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with conventional power plant generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, SO_2 and sulfuric acid mist as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective AAQS. The project impacts are less than the significant impact levels, which in-turn, are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Impact On Visibility

Natural gas and low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions will also minimize plume opacity. Because no add-on control equipment and no reagents are required, there will be no steam plume or tendency to form ammoniated particulate species.

Due to the close proximity of this project to the ONWA Class I area, a multi-tiered regional haze analysis was performed. The first tier consisted of a regional haze analysis utilizing the California

Puff (CALPUFF) modeling system in a screening mode otherwise known as CALPUFF Lite. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. CALPUFF requires the use of the CALMET model for preparation of meteorological data, whereas CALPUFF Lite utilizes the same meteorological data that is input into the ISCST3 model. As a result, CALPUFF Lite often overestimates visibility impacts and is adequate for use as a screening tool. CALPUFF is recommended by the National Park Service (NPS) for use in regional haze analyses because of its ability to handle atmospheric chemical transformations as well as wet/dry deposition.

The results of the CALPUFF Lite modeling analysis indicated a change in visibility of 5.6% and 27.2% for natural gas and fuel oil, respectively. Both of these values were greater than the NPS threshold of 5%. However, the cumulative effects of this project include the shut down of the JEA Southside Station. The Southside shut down will result in a net decrease in SO_2 and PM/PM_{10} emissions. Therefore, the proposed project will not result in adverse impacts on visibility in the ONWA.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the additional unit will require 6 more permanent employees, which will cause no significant impact on the local area.

Over the past few years the Public Service Commission has determined that a number of power projects are needed will help meet the low electrical reserve capacity throughout the State of Florida. The project is a response to statewide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint," low water requirements, and the among the lowest air emissions per unit of electric power generating capacity for intermittent duty.

Hazardous Air Pollutants

The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any specific industry or HAP control requirements pursuant to Section 112 of the Clean Air Act.

8. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations, provided the Department's BACT determination is implemented.

A. A. Linero, P.E., Administrator
Michael P. Halpin, P.E., Permit engineer
Chris Carlson, Meteorologist

PERMITTEE:

Jacksonville Electric Authority
Brandy Branch Facility
21 West Church Street
Jacksonville, Florida 32202-3139
Authorized Representative:

Walter P. Bussells, Chief Executive Officer

File No.	PSD-FL-267
FID No.	0310485
SIC No.	4911
Expires:	

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators and three 90-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability. They are designated by JEA as Combustion Turbine Generators 1, 2 and 3 and by the Department as ARMS Emissions Units 001, 002 and 003.

The project will be located approximately 1 mile N.E. of Baldwin City, Duval County. UTM coordinates are: Zone 17; 408.81 km E; 3354.38 km N.

STATEMENT OF BASIS:

This PSD 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 40CFR52.21. The above named permittee is authorized to modify the facility 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 of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with three 90-foot stacks and three fuel oil storage tanks.

Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS Emissions Unit	System	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Simple Cycle Combustion Turbine-Electrical Generator
002	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
003	Power Generation	One nominal 170 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
005	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank
006	Fuel Storage	1 Million Gallon Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

The 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 (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 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). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 08/xx/99 Notice of Intent published in The XXXXX
- 08/12/99 Distributed Intent to Issue Permit
- 08/06/99 Application deemed complete
- 05/18/99 Received Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on May 18, 1999
- Department letters dated May 26 and July 21, 1999
- Comments from the National Park Service dated July 20, 1999
- Letter from JEA dated June 21, 1999
- Letter (e-mail) from JEA dated August 4, 1999 and related submittals
- Department's Intent to Issue and Public Notice Package dated August 12, 1999
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: 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 (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Northeast District office, 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256 and phone number 904/448-4300; additionally, such documents shall be submitted to RESD, Suite 225, 117 W. Duval St., Jacksonville, Florida 32202 and phone number 904/630-3484.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: 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. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]

6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].

7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation (e.g. conversion to combined-

cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 52.21(j)(4), Rule 62-4.070 F.A.C.]

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Northeast District office as well as RESD. [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Northeast District office as well as RESD by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit [Rule 62-4.080, F.A.C.]

13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to the DEP's N.E. District office as well as RESD. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

14. Retirement of existing facility: In accordance with JEA's analyses of regional haze in the nearby Class I areas, the Brandy Branch facility may cause or contribute to haze values greater than 5%. In order to mitigate this possibility, JEA shall retire the existing Southside Facility (AIRS ID 0310046) located at 801 Colorado Avenue, Jacksonville, Florida upon JEA's application for a Title V permit for the Brandy Branch facility (including certification that the facility is in compliance with applicable requirements and permit conditions). JEA shall concurrently submit a letter from the designated representative of the Southside facility certifying that the facility has been shutdown and that related permits are being surrendered. This shall occur on or before October 31, 2001.

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.
2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

- 40CFR60.7, Notification and Recordkeeping
- 40CFR60.8, Performance Tests
- 40CFR60.11, Compliance with Standards and Maintenance Requirements
- 40CFR60.12, Circumvention
- 40CFR60.13, Monitoring Requirements
- 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]
5. ARMS Emission Units 004-006, Fuel Storage, consisting of three 1 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]
6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Northeast District office as well as RESD.

GENERAL OPERATION REQUIREMENTS

7. <u>Fuels</u>: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] {Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,623 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,822 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. 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.]

10. 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 owner or operator shall notify the DEP Northeast District office and RESD as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the 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 and the regulations. [Rule 62-4.130, F.A.C.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

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

13. Maximum allowable hours: The stationary gas turbines shall only operate up to 4000 hours during any calendar year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

14. Fuel usage as heat input, while burning natural gas at the site, shall not exceed 19.476×10^{12} BTU (LHV) per year during any consecutive 12 month period. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

15. Fuel usage as heat input, while burning fuel oil at the site, shall not exceed 4.099×10^{12} BTU (LHV) per year during any consecutive 12 month period. Fuel usage as heat input, while

burning fuel oil at the site, shall not exceed 8.746 x 10^{10} BTU (LHV) on a daily basis. Additionally, the amount of back-up fuel (fuel oil) burned at the site (in BTU's) shall not exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) during any consecutive 12-month period. Note: Basis for daily fuel oil limit is 16 hrs. of daily operation. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

Control Technology

16. Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rule 62-4.070, F.A.C.]

17. The permittee shall design each stationary combustion turbine, ducting, and stack(s) so as to not preclude installation of SCR equipment and/or oxidation catalyst in the event of a failure to achieve the NO_X limits given in Specific Condition No. 20 and 21 or the carbon monoxide (CO) limits given in Specific Condition 22. [Rule 62-4.070, F.A.C.]

18. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

19. The DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62-4.070 and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

20. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15% O_2 on a dry basis. [Rule 62-212.400, F.A.C.]

Operational Mode (Fuel)	NO_X (15%O2)	CO	VOC	PM/Visibility (% Opacity)	SO_2/SAM	*Technology and Comments*
Natural Gas	10.5 ppm	12 ppm	2 ppm	10	2 grain S per 100 CF	Dry Low NOx Burners. Clean fuels, good combustion
Fuel Oil	42 ppm	20 ppm	3.5 ppm	10	0.05% sulfur oil	Water Injection. Units limited to 750 hrs equivalent full load oil operation (per CT) annually. Clean fuels, good combustion

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

21. Nitrogen Oxides (NO_X) Emissions:

- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- While firing Natural Gas: The emission rate of NO_X in the exhaust gas shall not exceed 69.3 lb/hr (at ISO conditions) on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 10.5 ppm @15% O_2 to be demonstrated by annual stack test nor 9 ppm @15% O_2 to be demonstrated by the initial "new and clean" GE performance stack test. Note: Basis for lb/hr limit is 10.5 ppm @ 15% O_2, full load. [Rule 62-212.400, F.A.C.]
- While firing Fuel oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 42 ppm @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- Within 18 months after the initial compliance test, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest NO_X emission rate that can consistently be achieved when firing distillate oil. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the NO_X emission rate based upon this report. [BACT determination]

22. Carbon Monoxide (CO) emissions: The concentration of CO in the exhaust gas when firing natural gas shall not exceed 12 ppmvd when firing natural gas and 20 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 38.4 lb/hr (when firing natural gas) and 65.0 lb/hr (when firing fuel oil). [Rule 62-212.400, F.A.C.]

23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions (at ISO conditions) shall not exceed 1.1 pounds per hour when firing pipeline natural gas and 98.2 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. [Rule 62-212.400, F.A.C.]

24. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 or superior grade of fuel oil, except for during startup and shutdown at which time emissions shall not exceed 20 percent opacity. [Rule 62-296.320(4)(b), F.A.C.]

25. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 2 ppmvd when firing natural gas and 3.5 ppmvd when firing fuel oil as assured by EPA Methods 18, and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 4.0 lb/hr (when firing natural gas) and 7.5 lb/hr (when firing fuel oil). [Rule 62-212.400, F.A.C.]

EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open). Excess emissions 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 pursuant to Rule 62-210.700, F.A.C.

27. Excess Emissions Report: If excess emissions occur due to malfunction, start-up or shut-down the owner or operator shall notify DEP's Northeast District office and RESD within (1) working day 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. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.

29. Initial (I) performance tests shall be performed on each unit while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after starting the CT) to air pollution control equipment, including low NO_X burners or SCR. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (EPA reference Method 7E,

"Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement).

- EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

30. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN technology) or a 3-hr average (if SCR is used). For the 24-hr block average (lb/hr) emissions may be determined via EPA Method 19 or equivalent EPA approved methods. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Conditions 26 and 27. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

31. Compliance with the SO_2 and PM/PM_{10} emission limits: Notwithstanding the requirements of Rule 62-297.310(7), F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-941 or D4294-90 (or equivalent latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent latest version) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1997 version).

32. Compliance with CO emission limit: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for NO_X required pursuant to 40 CFR 75 (required for gas only).

33. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the BACT VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required.

34. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air

temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-204.800 F.A.C.

35. Test Notification: The DEP's Northeast District office and RESD shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s). [40 CFR 60.11]

36. Special Compliance Tests: The DEP or RESD may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

37. Test Results: Compliance test results shall be submitted to RESD and the DEP's N.E. District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by JEA shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP and RESD representatives upon request.

39. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition 37. above. 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), F.A.C.

40. Special Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to fuel usage:

    (1) Monthly Fuel usage as heat input, for natural gas and fuel oil at the site.

    (2) Fuel usage as heat input, for natural gas and fuel oil at the site for each consecutive 12-month period.

    (3) Fuel usage as heat input, for natural gas and fuel oil at the site during each calendar year shall be submitted with the Annual Operation Report (AOR).

(4) Hours of operation for each combustion turbine shall be reported during each calendar year with the Annual Operation Report (AOR).

(5) Daily fuel oil usage records, as heat input shall be kept at the site.

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from each (CT) unit. Periods when NO_X emissions are above the standards as listed in Specific Condition No 21, shall be reported to RESD and the DEP Northeast District Office pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards listed in Specific Condition No. 21 except as noted in Specific Condition No. 30. [Rule 62-204.800 and 40 CFR 60.7 (1997 version)]

42. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). The calibration of the water/fuel-monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

43. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Northeast District Office as well as RESD for review at least 90 days prior to installation.

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the Brandy Branch Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

SECTION III. EMISSION UNITS SPECIFIC CONDITIONS

- The permittee shall apply for an Acid Rain permit when the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant of 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USAEPA.
- JEA shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

46. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

JEA Brandy Branch Facility
PSD-FL-267 and 0310485-001-AC
Duval County, Florida

BACKGROUND

The applicant, JEA (formerly Jacksonville Electric Authority) proposes to install three nominal 170 megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Brandy Branch Facility near Baldwin City, Duval County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 90-foot stacks. JEA proposes to operate these units up to 4000 hours on natural gas and 800 hours on maximum 0.5 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated August 11, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on May 18, 1999 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E. and Michael P. Halpin, P.E., Permit Engineer

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	12 ppmvd @ 15% O_2 (gas) 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (876 hr/yr) Combustion Controls	10% Opacity
Carbon Monoxide	As Above	15 ppm (gas, baseload) 20 ppm (oil baseload)
Sulfur Dioxide	As Above	0.05% S in fuel oil
Sulfuric Acid Mist	As Above	0.05% S in fuel oil

According to the application, the maximum emissions from the facility will be approximately 858 tons per year (TPY) of NO_X, 366 TPY of CO, 75 TPY of PM/PM_{10}, 124 TPY of SO_2, 15 TPY of SAM, and 21 TPY of VOC.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by JEA is within the NSPS limit, which allows NO_X emissions, over 110 ppmvd for the high efficiency unit to be purchased for the Brandy Branch Facility.

No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY EPA AND STATES:

The following table is based primarily on "F" Class intermittent-duty simple cycle turbines recently permitted or still under review. One project (PREPA) based on smaller units but permitted to operate continuously is included as an example of a simple cycle unit with add-on control equipment. Another continuous-duty project (Lakeland) based on the larger "G" Class is also included. The proposed JEA Brandy Branch project is included to facilitate comparison.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output and Duty	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Lakeland, FL	250 MW SC CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
Oleander Cocoa, FL	850 MW SC INT	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Draft 4/99. 1000 hrs on oil
JEA Brandy, FL	510 MW SC INT	12 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Application 5/99. 800 hrs on oil
JEA Kennedy, FL	170 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	170 MW GE MS7241FA CT Issued 2/99. Not PSD/BACT
TEC Polk Power, FL	330 MW SC INT	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Application 2/99. 876 hrs on oil
Dynegy Heard, GA	510 MW SC INT	15 – NG	DLN	3x170 MW WH 501F CTs Application. Gas only
Tenaska Heard, GA	960 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680 MW SC INT	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Application. 1687 hrs on oil
Dynegy Reidsville, NC	900 MW SC INT	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Draft 5/98. 1000 hrs on oil.
RockGen Cristiana, WI	525 MW SC INT	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
SEI Neenah, WI	330 MW SC INT	15/12 - NG 42 - No. 2 FO	DLN WI	2x165 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 8760/699 hrs gas/oil
PREPA, PR	248 MW SC CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous DLN = Dry Low NO_X Combustion FO = Fuel Oil GE = General Electric
SC = Simple Cycle SCR = Selective Catalytic Reduction NG = Natural Gas WH = Westinghouse
INT = Intermittent HSCR = Hot SCR WI = Water or Steam Injection ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
Oleander Cocoa, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Brandy, FL	15 - NG 20/26 (full/part load) - FO	1.4 – NG 1.4 – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
JEA Kennedy, FL	15 - NG 20 - FO	1.4 – NG 3.5 – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
SEI Neenah, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr - NG 41 lb/hr - FO	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from the Fish and Wildlife Service dated July 20, 1999
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Brandy Branch Station Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combustion Turbine Startup Curves
- JEA Website – www.jea.com
- Goal Line Environmental Technologies Website – www.glet.com
- Catalytica Website – www.catalytica-inc.com

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the JEA project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 800 hours per year (per CT).

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the JEA Project. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection increase emissions of both of these pollutants.

Combustion Controls

The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the JEA project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at Jacksonville Electric Authority's Kennedy Station.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X and 9 ppm of CO. Emissions characteristics while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the JEA project are shown in Figure 4.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from gas turbines smaller than 200 MW (simple cycle), such as GE "F Class" units. Even lower NO_X emissions are achieved from certain units smaller than 100 MW, such as the GE 7EA line.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Per the above table, only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. SCR is also proposed on a permanent basis for the expansion of the FPC Hines Facility (Power Block II). Seminole Electric will install SCR on a previously-permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Permit limits as low as 2.25 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

Emerging Technologies: SCONOX™ and XONON™

There are at last two technologies on the horizon that will influence BACT determinations. These, as usual, are prompted by the needs specific to non-attainment areas such as Southern California.

The first technology is called $SCONO_X$™ and is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires a dilute hydrogen reducing gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[1] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at U.S. Generating's La Paloma Plant near Bakersfield.[2] The overall project includes several more 250 MW blocks with SCR for control.[3] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of some CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas.

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx™ process was deemed as technically feasible for maintaining NO_X emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). SCONOx requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the SCONOx system cannot be considered as achievable or demonstrated in practice for this application.

The second technology is XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as $SCONO_X$ ™ has. However GE has teamed with Catalytica to develop a combustor for gas turbines in the 80-90 MW range before continuing with development on a combustor for a larger unit. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

Catalytica's XONON™ system is represented as a powerful technology that essentially eliminates the formation of nitrogen oxides air emissions in gas turbines without impacting the turbine's operating performance. In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E-class and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil and pipeline natural gas. The applicant estimated total emissions for the project at 124 TPY of SO_2 and 15 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 1 grain of sulfur per 100 standard cubic feet (gr S/100ft^3). This value is well below the "default" maximum value of 20 gr. S/100 ft^3, but high enough to require a BACT determination.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 800 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 75 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[4]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations typically achieve emissions between 10 and 25 ppm at full load while firing gas. The values of 15 and 20 ppm for gas and oil respectively at baseload proposed in JEA's original application are within the range of recent determinations for simple cycle CO BACT determinations. By comparison, values of 12 and 20 ppm for gas and oil respectively (at baseload) were proposed for the Oleander's project using identical equipment. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by JEA for this project are 1.4 ppm for both gas and oil firing at baseload. According to GE, however, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[5] By comparison, limits of 3 and 6 ppm were proposed for gas and oil firing respectively in the Oleander application. The limits proposed by JEA are sufficiently low to exempt the Brandy Branch project from BACT for VOC.

BACKGROUND ON PROPOSED GAS TURBINE

JEA plans the purchase of three 170 MW (nominal) General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

The first commercial GE 7F Class unit was installed in a combined cycle project at the Virginia Power Chesterfield Station in 1990.[6] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[7] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppm of CO, and 0-0.17 ppm of VOC.[8] The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[9] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[10] FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for six GE 7241FA turbines to be installed at the Fort Myers Repowering project.[11] The Santa Rosa Energy Center in Pace, Florida, also received a permit with a 9 ppmvd NO_X limit for a GE 7241 turbine with DLN-2.6 burners.[12]

Most recently, the Department issued draft BACT determinations for the simple cycle Oleander project in Brevard County and the combined cycle projects in Volusia (Duke Energy) and Osceola County (Kissimmee Utilities). These three draft permits also include NO_X limits of 9 ppmvd based on the DLN-2.6 technology installed on F Class units.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[13] In its recent permits, Florida has included separate and lower limits in the event that DLN emissions limits are not attainable or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[14] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[15] Unit 2 is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line such as the one that will be installed for the JEA Brandy Branch Project. Performance guarantees less than 9 ppmvd can be expected for DLN-2.6 combustors on units delivered in a couple of years.[16]

The 12 ppmvd NO_X limit on natural gas proposed by JEA is a fairly stringent BACT determination for simple cycle F Class, though it is becoming less so. The company has obtained a guarantee from GE to achieve 9 ppmvd, which is for a performance test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation as specified in the GE protocols.

With the frequent start-ups and shutdowns of the unit, JEA is concerned about the ability to maintain the low (9 ppmvd) NO_X values for long periods of time following the performance tests. Presumably, this concern would be lessened should these units be converted to a more continuous duty (i.e. combined cycle). Although the Department is not fully aware of the details of the GE guarantee for Oleander (proposed 9 ppmvd on a simple cycle unit), the Department is aware from discussions with other applicants that a continuing guarantee is available at a substantial cost.[17]

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low NO_X techniques, fuel staging and combustion mode are also controlled by the Mark V, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V.[18]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the JEA project assuming full load. Values for NO_X are corrected to 15% O_2 on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 20 through 25.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity
CO	As Above	12 ppm – Gas 20 ppm – Fuel Oil
SO_2/SAM	As Above	2 grains of sulfur per 100 ft^3 gas 0.05 percent sulfur in fuel oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	10.5 ppmvd – Gas 42 ppmvd – F.O. for 750 of 4000hours

RATIONALE FOR DEPARTMENT'S DETERMINATION

- General Electric has provided a "clean and new" one time guarantee of 9 ppmvd NO_X.
- Typical "continuous" permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 12-15 ppmvd even though GE provides the same "new and clean" guarantees for them. Limits as high as 25 ppmvd have been recently proposed by some for similar units produced by other manufacturers.
- A level of 9 ppmvd NO_X by DLN has been demonstrated on GE 7FA combustion turbines at Fort St. Vrain, Colorado and Clark County, Washington. However the permitted limits are actually higher at these two facilities providing some level of operating margin.
- A limit of 9 ppmvd was proposed by Oleander for five GE7 FA units and is reflected in the Department's recent Draft BACT Determination for that facility. A BACT level of 9 ppmvd has been proposed by Virginia Power for a GE 7FA unit to avoid non-attainment New Source Review.
- The proposed 9 ppmvd limit at Oleander and Virginia Power while firing natural gas is the lowest known Draft BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42 ppmvd limit while firing fuel oil is typical.
- The Department prepared a Draft permit for the TEC Polk Power Station Project adopting TEC's proposed 10.5 ppmvd limit for two GE 7FA units, but limited the hours of operation on fuel to less than the hours allowed at Oleander. The TEC Draft BACT is being issued concurrently with the Draft BACT for the JEA project.
- JEA's proposed 12 ppmvd limit for the Brandy Branch Facility while firing natural gas is relatively low for a GE 7FA Class simple cycle, intermittent duty unit.
- The Department, however proposes a BACT limit of 10.5 ppmvd which is the same as proposed for the TEC project. The Department also proposes to limit oil firing to the same number of hours as TEC (750) and less than the number of hours at Oleander (1000).
- The Department will still require JEA to meet to meet the "clean and new" limit of 9 ppmvd during initial testing as well as requiring a continuous 9 ppmvd guarantee in the event that JEA converts the units to continuous duty (i.e. combined cycle).
- The proposed BACT limit of 10.5 ppmvd is about one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- The units will be operated in simple cycle mode. Therefore control options, which are feasible for combined cycle units, are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 4.5 ppmvd NO_X or lower. It also rules out the possibility of SCONOx. XONON is not available for F Class dual fuel projects.
- The simple cycle "F Class" turbines have very high exhaust temperatures of up to 1200 °F. This is at the higher limit of the present operational temperature of Hot SCR zeolite catalyst (around 1050 °F). The PREPA simple cycle turbines, which use Hot SCR, have exhaust temperatures ranging from 824 to 1024 °F.

- The levelized costs of NO_X removal by Hot SCR for the JEA project were estimated by Black & Veatch at $13,380 per ton assuming 4000 hours of operation on natural gas and a reduction from 12 to 5 ppmvd.
- TEC estimated the cost of Hot SCR at $9,717 per ton of NO_X removed assuming 4,380 and 876 hours per year of operation on gas and oil respectively.
- The Department previously concluded that Hot SCR is cost-effective for continuous duty simple cycle service (Lakeland). EPA also concluded Hot SCR is cost-effective on continuous duty simple cycle projects (PREPA).
- Although the Department does not have a "bright line" cost-effectiveness figure and does not necessarily adopt the precise cost calculations for the JEA and TEC projects, the values projected by JEA and TEC indicate that Hot SCR is not cost-effective for their respective projects.
- Comments from the National Park Service on the Oleander project suggested that a reduction in the applicant's proposed NO_X emissions on oil from 42 ppmvd to 25 ppmvd is possible based on reported oil-fired units listed in the BACT Clearinghouse. GE has advised that it only offers a 42 ppmvd NO_X guarantee on F Class units when firing oil.
- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- It is possible that the NO_X emissions while firing oil from may be reduced from 42 ppmvd by increasing the water injection rate. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil have been achieved.
- The Department's overall BACT determination is equivalent to approximately 0.3 lb/MW-hr by Dry Low NO_X. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr.
- VOC emissions of 1.4 ppm while firing gas or oil proposed by the applicant clearly reflect BACT and, in fact, exempt the project from a BACT determination for VOC. The Department will set VOC limits at 2 ppm (gas) and 3.5 ppm (oil). These values are still sufficient to maintain VOC emissions to less than 40 tons per year.
- The Department will set CO limits achievable by good combustion at full load as 12 ppm (gas) and 20 ppm (oil). These values are equal to the lowest values from permitted or proposed simple cycle units. These limits are equal to those proposed by the Department for Oleander and TEC project.
- Black & Veatch evaluated the use of an oxidation catalyst for the JEA project with an 88 percent control efficiency and having a three-year catalyst life. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,905,000 with an annualized cost of $509,000 per year. Levelized costs for CO catalyst control were calculated at $4,700 per ton. This figure does not appear to be cost-effective for removal of CO.

- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels, and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 750 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, Santa Rosa Energy Center, FPL Fort Myers, and the Southern Company Barry projects.

Compliance Procedures

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)
NO_X (24-hr block average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
SO_2 and SAM	Custom Fuel Monitoring Schedule

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section
Michael P. Halpin, P.E., Review Engineer, New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By: | Approved By:

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

Date:

REFERENCES

[1] News Release. Goaline Environmental. Genetics Institute Buys SCONOx Clean Air System. August 20, 1999.

[2] "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.

[3] Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.

[4] Letter from Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee unit 3. December 9, 1998.

[5] Telecon. Vandervort, C., GE, and Linero, A.A., DEP. "VOC Emissions from FA Gas Turbines with DLN-2.6 Combustors."

[6] Brochure. General Electric. "GE Gas Turbines - MS7001FA." Circa 1993.

[7] Davis, L.B., GE. "Dry Low NO_X Combustion Systems for GE Heavy Duty Gas Turbines." 1994.

[8] Report. Florida Power & Light. "Final Dry Low NO_X Verification Testing at Martin Combine Cycle Plant." August 7, 1995.

[9] Florida DEP. PSD Permit, City of Tallahassee Purdom Unit 8. May, 1998.

[10] City of Tallahassee. PSD/Site Certification Application. April, 1997.

[11] Florida DEP. Intent to Issue Permit. FPL Fort Myers Repowering Project. September, 1998.

[12] Florida DEP. Final Permit. Santa Rosa Energy Center. December, 1998.

[13] State of Alabama. PSD Permit, Alabama Power/Barry Sithe/IPP (GE 7FA).

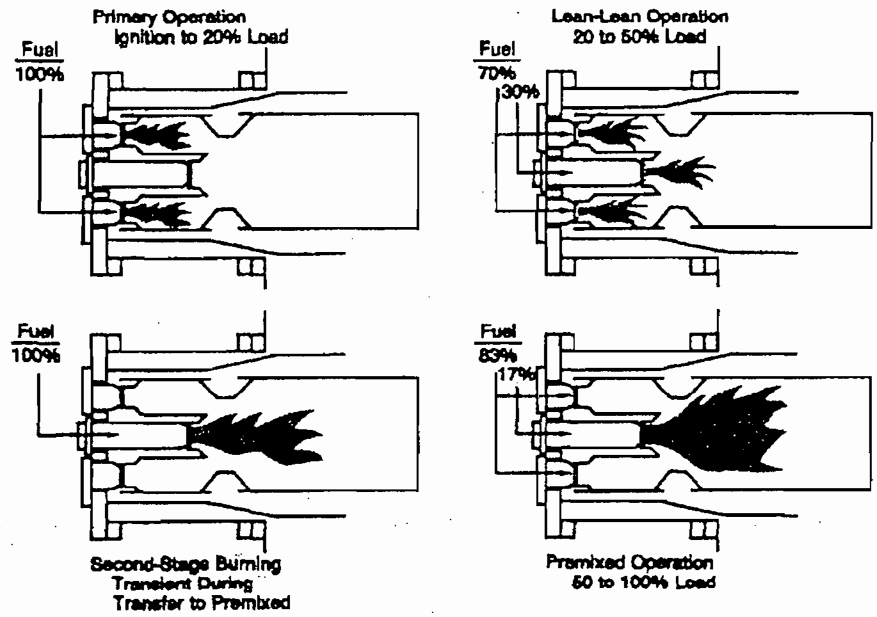
[14] Telecon. Schorr, M., GE, and Costello, M., Florida DEP. March 31, 1998. Status of DLN-2.6 Program

[15] Florida DEP. Bureau of Air Regulation Monthly Report. June, 1998.

[16] Telecon. Schorr, M., GE, and Linero, A.A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.

[17] Telecon. Gianazza, N.B., JEA, and Linero, A.A., Florida DEP. Proposed NO_X limits at Brandy Branch Project.

[18] Rowen, W.I. "General Electric Speedtronic™ Mark V Gas Turbine Control System. 1994."



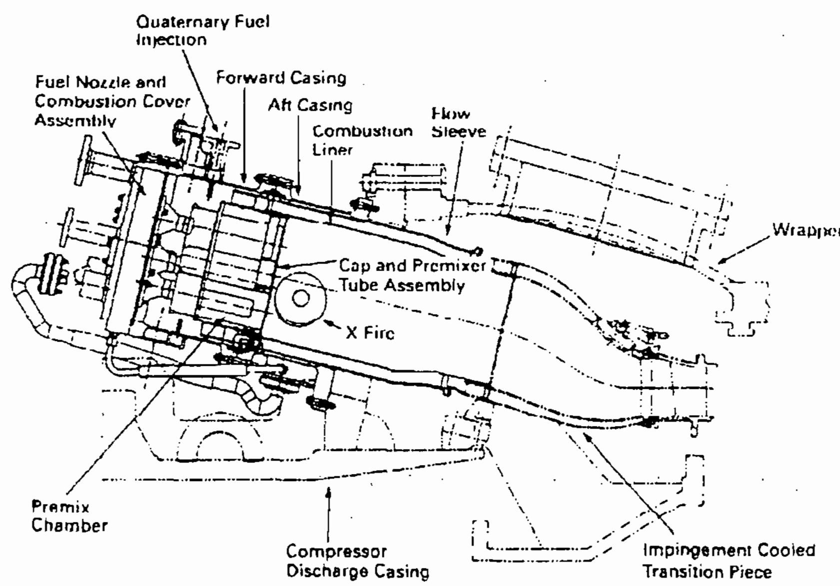


Figure 1 - Dry Low NOx Operating Modes - DLN-1

Cross Section of GE DLN-2

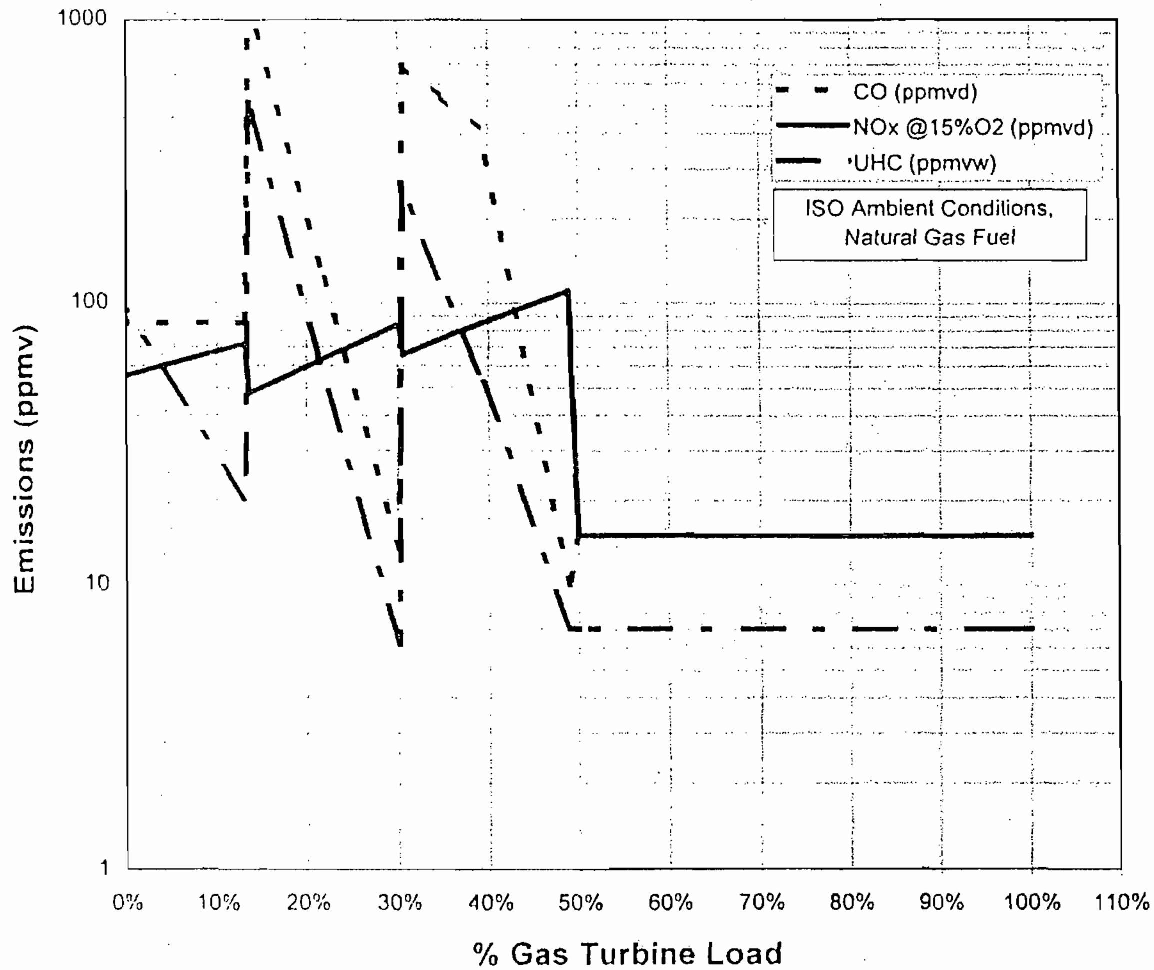


Figure 2 - Emissions Performance Curves for GE DLN-2.6 Combustor

Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle, Intermittent Duty - If Tuned to 15 ppm NOx)

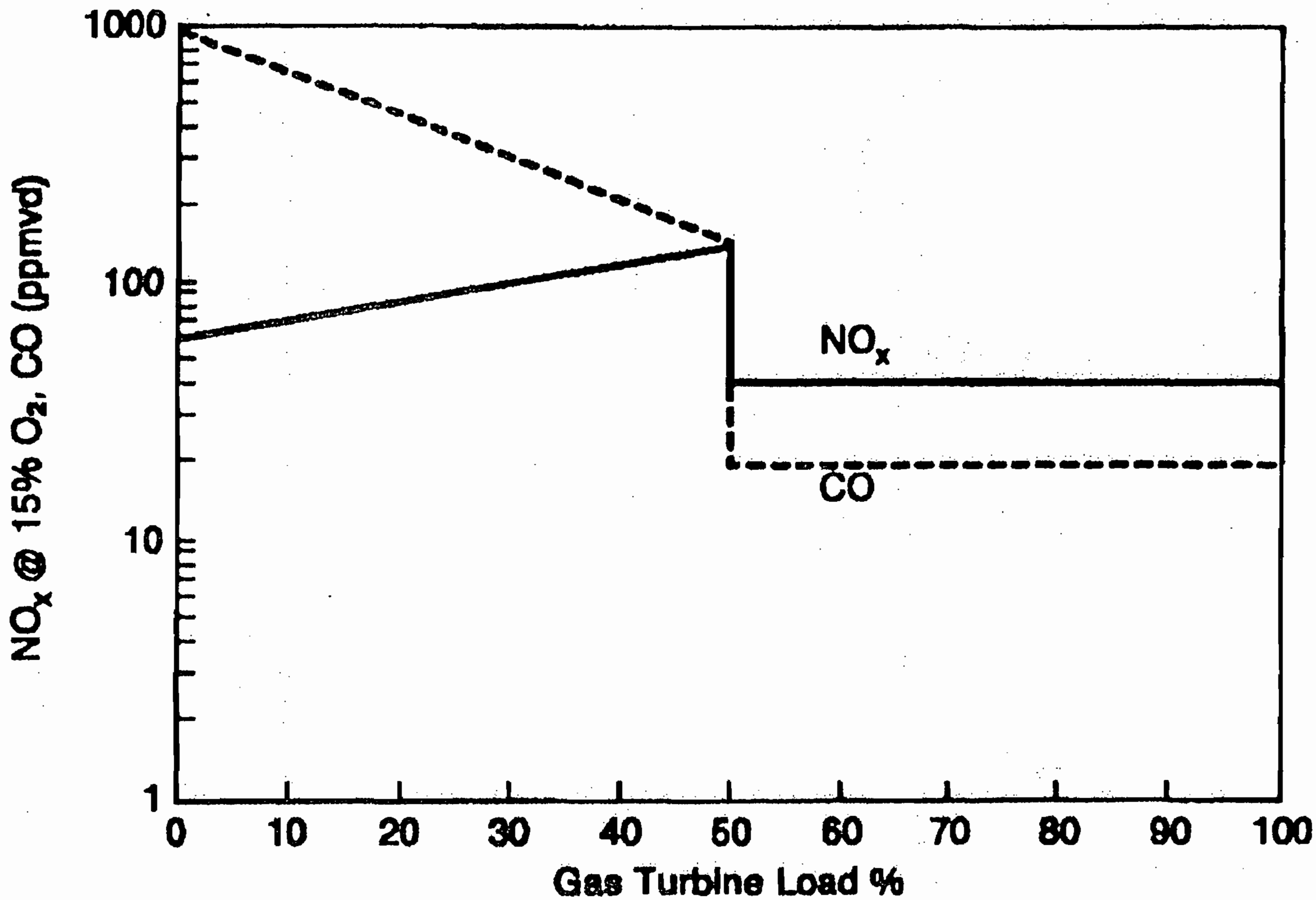


Figure 3 - Emissions Performance for DLN-2 Combustors

Firing Fuel Oil in Dual Fuel GE 7FA Turbine

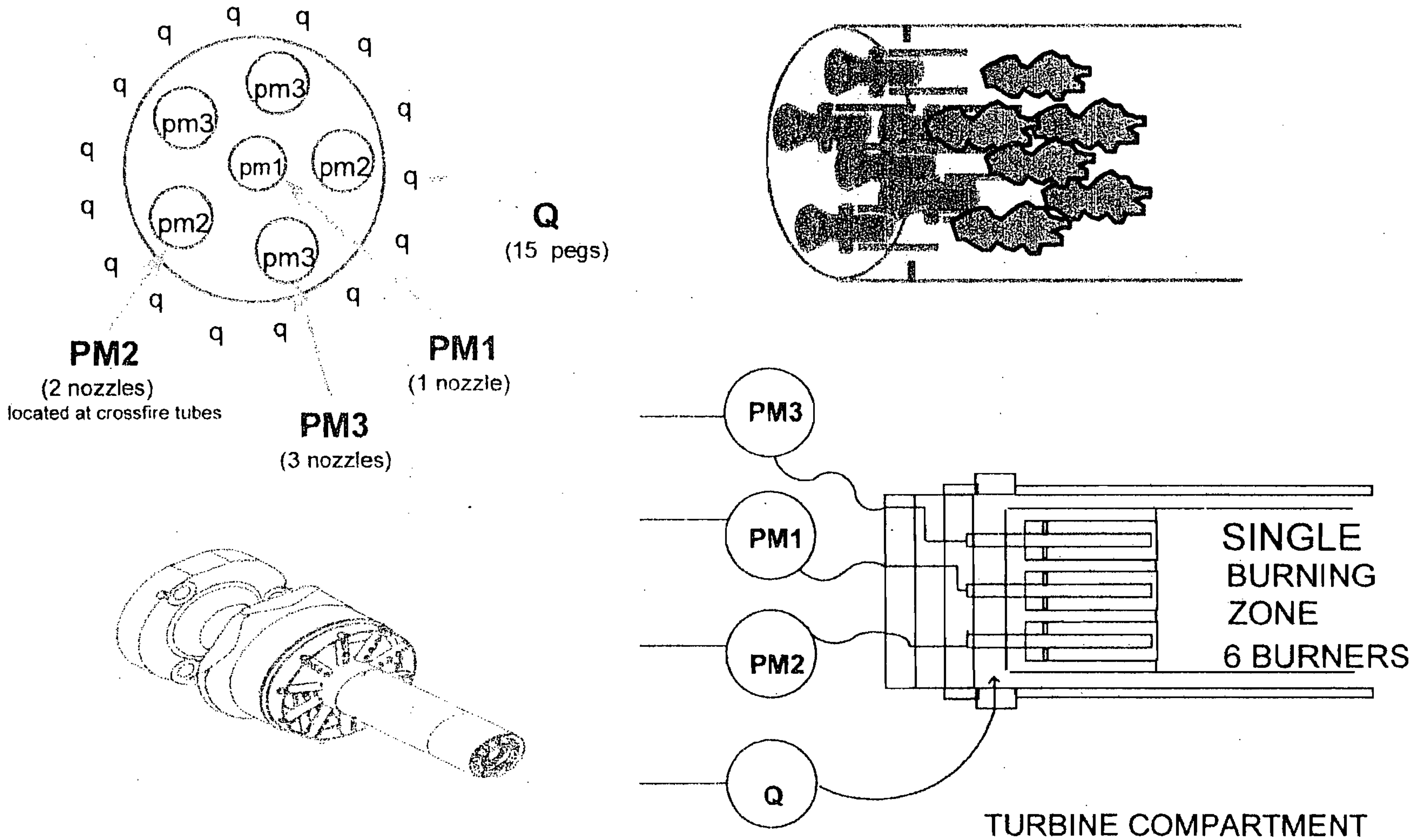


Figure 4 - DLN-2.6 Nozzle and Burner Arrangement

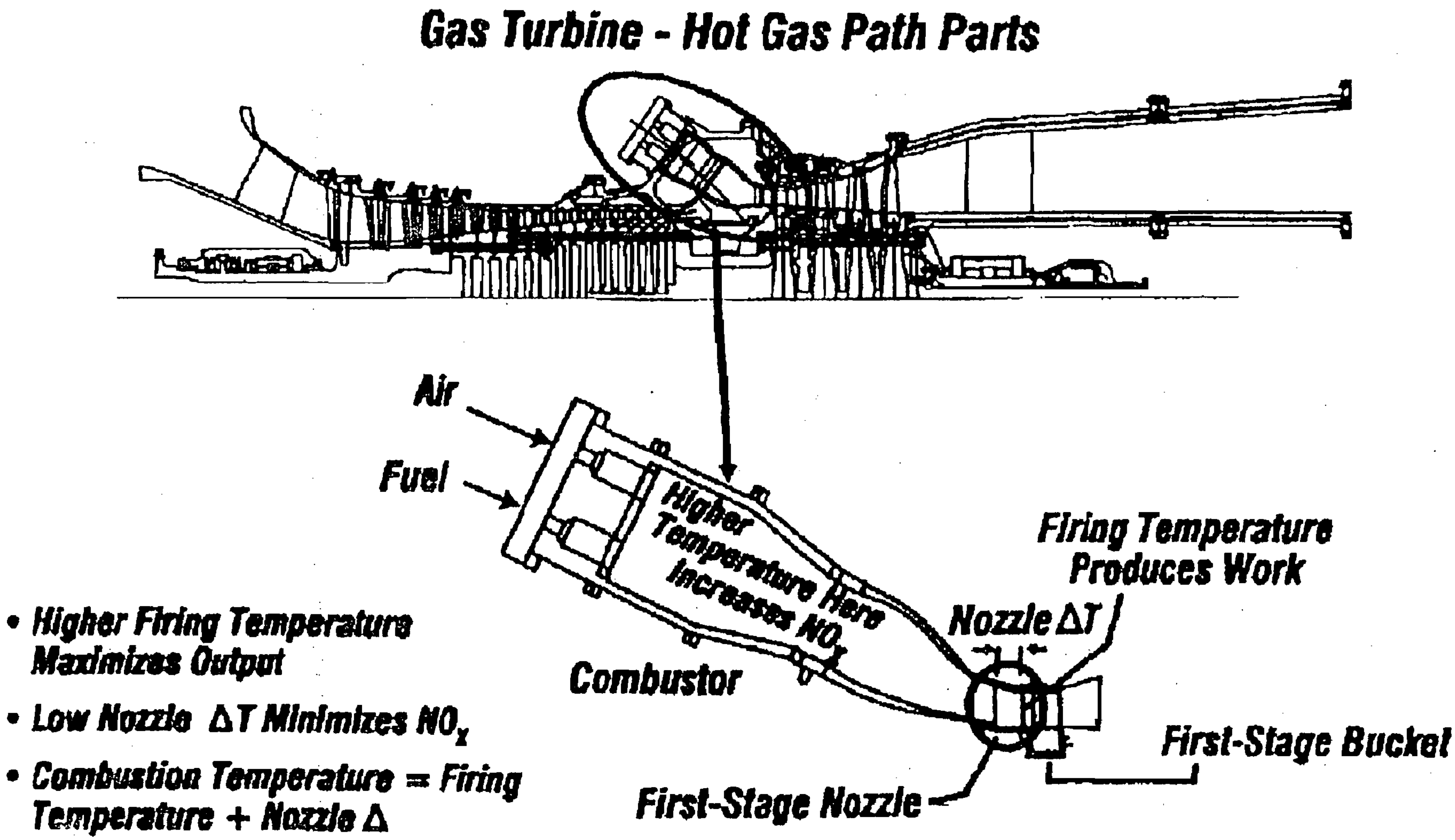


Figure 5 - Relation Between Flame Temperature and Firing Temperature

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

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

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

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

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

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

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

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

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

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

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

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

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

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

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

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (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.

Z 333 618 124

US Postal Service

Receipt for Certified Mail

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Sent to Walter Brussels	
Street & Number JEA - BB	
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Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 8-12-99 0310485-001-AC PSD-Fl-267	

PS Form **3800**, April 1995

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- Complete items 3, 4a, and 4b.
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- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

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3. Article Addressed to:
Walter Brussels
JEA - Brandy Branch
21 W. Church St.
Jacksonville, Fl
32202-3139

4a. Article Number
Z 333 618 124

4b. Service Type
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X D. Grace

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

THRU: Al Linero AAL 8/11

FROM: Michael P. Halpin

DATE: August 11, 1999

SUBJECT: JEA Brandy Branch Facility
Three 170 MW Combustion Turbines
DEP File No. 0310485-001-AC (PSD-FL-267)

Attached is the public notice package for construction of three dual-fuel, intermittent duty, simple cycle, 170 MW combustion turbines at the planned JEA Brandy Branch Facility.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by Dry Low NO_X (DLN-2.6). We propose to require that the unit meet the manufacturer's new and clean (one-time) guarantee of 9 ppm, and a continuous (24-hour average) emission limit of 10.5 ppm. The use of fuel oil will be limited to 750 hours from the 800 hours requested as a means of being consistent. We recently issued a draft permit for identical NO_X and fuel oil firing characteristics (750 hours) at TEC Polk Power station.

NO_X emissions will be controlled to 42 ppm during the limited fuel oil use. Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and, especially, the design of the GE unit.

Recent simple cycle emission limits in Region IV have typically been at 15 ppm for simple cycle "F Class" units. In fact, North Carolina recently issued a draft BACT to Dynegy for six dual-fuel Westinghouse "F Class" units with limits of 25 ppm. The Dynegy Westinghouse units must meet 15 ppm by early 2002.

For reference, the draft BACT requested by Oleander is a continuous limit of 9 ppm. Oleander will be allowed to operate on fuel oil for 1000 hours instead of the 2000 hours they requested (or the 750 hours to which JEA will be limited). Oleander is either more willing than JEA to take a risk on continuous compliance or more willing to pay for a continuing guarantee. Oleander's parent company, Constellation, included an identical simple cycle project for its planned High Desert Project in California where LAER is required. They undoubtedly tried to get them permitted for the lowest emission rate while avoiding SCR. When they shifted the simple cycle option to the Florida site, they decided to propose 9 ppm.

This intent is being issued with the NPS concurrence that JEA's regional haze analysis (for the Class I areas) is satisfactory. This concurrence has been achieved due to JEA's commitment to shutdown its Southside Station (as a means of mitigating any modeled haze problems) yielding a corresponding 100% offset in PM_{10} and a net reduction of over 700 TPY of SO_2 in Duval County. The Southside Station shutdown has been addressed in the Draft permit as a condition.

Accordingly, I recommend your approval of the attached Intent to Issue.

AAL/mph

Attachments

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

JEA (formerly Jacksonville Electric Authority)
Brandy Branch Facility
Duval County

DEP File No.: 0310485-001-AC (PSD-FL-267)
Facility ID No.: 0310485

Project: Air Construction Permit

I HEREBY CERTIFY that the engineering features described in the above referenced application and related additional information submittals, if any, 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).

Chris Carlson and I conducted this review.

Michael P. Halpin, P.E.
Registration Number: 31970

8-11-99
Date

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

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

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

August 11, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. Douglas Neeley, Chief
Air, Radiation Technology Branch
US EPA Region IV
61 Forsyth Street
Atlanta, GA 30303

Re: PSD Review and Custom Fuel Monitoring Schedule
JEA Brandy Branch Facility
PSD-FL-267

Dear Mr. Neeley:

Enclosed is a copy of the draft permit to construct (the Department's Intent to Issue package was already mailed to Mr. Greg Worley) the JEA Brandy Branch Power Plant in Duval County. It will be a natural gas and oil-fired simple cycle facility consisting of three nominal 170-megawatt (MW) simple cycle combustion turbine-electrical generators.

The project is not subject to the Florida's Power Plant Siting procedure because it will generate no electricity from steam.

Please send your written comments on or approval of the applicant's proposed custom fuel monitoring schedule. The plan is based on the letter dated January 16, 1996 from Region V to Dayton Power and Light. The Subpart GG limit on SO_2 emissions is 150 ppmvd @ 15% O_2 or a fuel sulfur limit of 0.8% sulfur. Neither of these limits could conceivably be violated by the use of pipeline quality natural gas which has a maximum SO_2 emission rate of 0.0006 lb/MMBtu (40 CFR 75 Appendix D Section 2.3.1.4). The sulfur content of pipeline quality natural gas in Florida has been estimated at a maximum of 0.003 % sulfur. Fuel oil with a 0.05% sulfur content will be used as a backup. The requirements have been incorporated into the enclosed draft permit as Specific Conditions 44 and 45 and read as follows:

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the Brandy Branch Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- The permittee shall apply for an Acid Rain permit when the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant of 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USAEPA.

JEA shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

Please comment on Specific Conditions 30 and 41 which allow the use of the acid rain NO_X CEMS for demonstrating compliance as well as reporting excess emissions, as well as Specific Condition 42 which allows the use of CEMS in lieu of measuring the water to fuel ratio. Typically NO_X emissions will be less than 11 ppmvd @15% O_2 (natural gas) which is less than one-tenth of the applicable Subpart GG limit based on the efficiency of the unit. A CEMS requirement is stricter and more accurate than any Subpart GG requirement for determining excess emissions.

The Department recommends your approval of the custom fuel monitoring schedule and these NO_X monitoring provisions. We also request your comments on the Intent to Issue. If you have any questions on these matters please contact Michael P. Halpin, P.E. at 850/921-9530.

Sincerely,

8/11

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

AAL/mph

Enclosures

Z 333 618 123

US Postal Service

Receipt for Certified Mail

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Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date JEA Brandy 8-12-99 POD-F1-267 03104855-00LAC	

PS Form **3800**, April 1995

SENDER:
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- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Doug Neeley, Chief
Air, Radiation Tech. Br.
US EPA Region 4
61 Forsyth St.
Atlanta, GA 30303

4a. Article Number
Z 333 618 123

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery

5. Received By: *(Print Name)* JOYCE EVANS

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)* AUG 16 1999
X

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PS Form **3811,** December 1994 102595-98-B-0229 Domestic Return Receipt

BLACK & VEATCH

8400 Ward Parkway
P.O. Box 8405
Kansas City, Missouri 64114

Tel: (913) 458-2000

Black & Veatch Corporation

Jacksonville Electric Authority
Brandy Branch Facility

RECEIVED
AUG 04 1999
BUREAU OF AIR REGULATION

B&V Project 60903
B&V File 32.0203
August 3, 1999

Christopher R. Carlson
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

Subject: Additional SO_2 Impact Analysis

Dear Mr. Carlson:

Enclosed with this letter is the Revised Okefenokee Wilderness Area SO_2 Impact Analysis for Jacksonville Electric Authority you requested. This report summarizes all modeling that was preformed for this analysis. The additional ten receptors you requested were included into the modeling files and the results of the new modeling runs are presented in table format.

If you have any questions, feel free to contact me at (913) 458-9194 or e-mail me at dilloncg@bv.com.

Very truly yours,

BLACK & VEATCH

Chris G. Dillon

Chris G. Dillon
Air Quality Scientist
Black & Veatch

cgd
Enclosure[s]

cc: Ellen Porter, National Park Service
Bert Gianazza, Jacksonville Electric Authority

Revised Okefenokee Wilderness Area SO_2 Impact Analysis for Jacksonville Electric Authority

At the request of the Florida Department of Environmental Protection (FDEP), an additional Class I impact analysis was conducted for the Jacksonville Electric Authority (JEA) Brandy Branch Project. This analysis included 26 additional Putnam County SO_2 sources and 10 additional receptor locations in the Okefenokee Wilderness Area. These sources and receptors were not included in the original Class I impact analysis. This additional impact analysis consists of Prevention of Significant Deterioration (PSD) Significant Impact Level (SIL) and Increment modeling for SO_2 in the Class I area only.

All modeling was conducted using the currently requested permit limitation of a maximum of 16 hours of fuel oil firing and 8 hours of natural gas firing per day. A spreadsheet containing the enveloped emissions used in the modeling can be found in Attachment A. This modification changes the previously used 24-hour emission rate, but does not effect the 3-hour values. The 3-hour values are unchanged due to the fact the 3-hour averaging period can occur during periods of fuel oil firing only. To obtain the new 24-hour emission rate the following equation was used:

FO emission rate (g/s) * (16hrs/24hrs) + NG emission rate (g/s) * (8hrs/24hrs)
= New 24-hour emission rate (g/s)

In addition, the PSD SILs modeling was run for all ambient temperatures (20° F, 59° F, and 95° F) and across all three loads (50%, 75%, and 100%). Following the initial PSD SIL analysis, additional modeling was completed only for the operating scenarios where exceedances occurred.

Revised PSD SIL modeling results, including the 10 new receptor locations for Okefenokee, are shown in Tables 1 through 5. The tables contain a total of 41 exceedances of the Class I SILs (Class I SILs are calculated as 4 percent of the PSD Class I SO_2 Increment). These 41 exceedances were then modeled against the Class I Increment values. The PSD Increment modeling results include all significant sources of SO_2 in this area, as well as the proposed

Brandy Branch Project, and are shown in Tables 6 and 7. These tables also present the operating scenarios that exceed the Class I SILs. As discussed in Section 5.3.1 of the Air Permit Application, the values presented in Tables 6 and 7 are the highest second-high model-predicted values. The results indicate that SO_2 Class I Increment values were exceeded 18 times at Okefenokee.

Additional modeling was then performed to determine if the proposed Brandy Branch Project was a significant contributor to any of the 18 modeled exceedances. This determination was made by modeling only the proposed Brandy Branch Project's emissions at each receptor location and period having a modeled Class I Increment exceedance. The resulting maximum predicted concentrations were then compared to the Class I SO_2 SIL. The results show that the proposed Project has no significant contribution to any modeled exceedance at Okefenokee. The results of this modeling, shown in Tables 8 and 9, indicate that the maximum predicted impacts from the proposed Brandy Branch Project were all significantly below the applicable Class I SO_2 SILs. Therefore, operation of the proposed Project will not cause or contribute to an exceedance of the Okefenokee Wilderness Area Class I SO_2 Increment.

Table 1					
ISCST3 Model Predicted SO_2 Concentrations for Class I SILs at Okefenokee					
ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
3951FO	3-Hour	100	1984	0.998	1.000
3957FO		75		0.934	1.000
3955FO		50		0.860	1.000
3591FO		100		**1.060**	1.000
3597FO		75		0.998	1.000
3595FO		50		0.908	1.000
3201FO		100		**1.098**	1.000
3207FO		75		**1.037**	1.000
3205FO		50		0.941	1.000
24951FO	24-Hour	100		0.150	0.200
24957FO		75		0.143	0.200
24955FO		50		0.132	0.200
24591FO		100		0.158	0.200
24597FO		75		0.152	0.200
24595FO		50		0.142	0.200
24201FO		100		0.164	0.200
24207FO		75		0.157	0.200
24205FO		50		0.144	0.200
*Calculated as 4 percent of the PSD Class I Increment					

Table 2

ISCST3 Model Predicted SO_2 Concentrations for Class I SILs at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	Class I SIL* (μg/m^3)
3951FO	3-Hour	100	1985	**1.075**	1.000
3957FO		75		**1.009**	1.000
3955FO		50		**1.009**	1.000
3591FO		100		**1.149**	1.000
3597FO		75		**1.068**	1.000
3595FO		50		0.990	1.000
3201FO		100		**1.194**	1.000
3207FO		75		**1.105**	1.000
3205FO		50		**1.027**	1.000
24951FO	24-Hour	100		0.168	0.200
24957FO		75		0.159	0.200
24955FO		50		0.144	0.200
24591FO		100		0.179	0.200
24597FO		75		0.169	0.200
24595FO		50		0.153	0.200
24201FO		100		0.185	0.200
24207FO		75		0.176	0.200
24205FO		50		0.159	0.200

*Calculated as 4 percent of the PSD Class I Increment

Table 3

ISCST3 Model Predicted SO_2 Concentrations for Class I SILs at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	Class I SIL* (μg/m^3)
3951FO	3-Hour	100	1986	**1.243**	1.000
3957FO		75		**1.167**	1.000
3955FO		50		**1.052**	1.000
3591FO		100		**1.328**	1.000
3597FO		75		**1.244**	1.000
3595FO		50		**1.121**	1.000
3201FO		100		**1.381**	1.000
3207FO		75		**1.293**	1.000
3205FO		50		**1.166**	1.000
24951FO	24-Hour	100		0.188	0.200
24957FO		75		0.179	0.200
24955FO		50		0.163	0.200
24591FO		100		0.198	0.200
24597FO		75		0.190	0.200
24595FO		50		0.173	0.200
24201FO		100		**0.205**	0.200
24207FO		75		0.197	0.200
24205FO		50		0.180	0.200

*Calculated as 4 percent of the PSD Class I Increment

Table 4

ISCST3 Model Predicted SO_2 Concentrations for Class I SILs at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
3951FO	3-Hour	100	1987	**1.196**	1.000
3957FO		75		**1.128**	1.000
3955FO		50		**1.017**	1.000
3591FO		100		**1.268**	1.000
3597FO		75		**1.203**	1.000
3595FO		50		**1.084**	1.000
3201FO		100		**1.312**	1.000
3207FO		75		**1.249**	1.000
3205FO		50		**1.127**	1.000
24951FO	24-Hour	100		0.163	0.200
24957FO		75		0.154	0.200
24955FO		50		0.139	0.200
24591FO		100		0.172	0.200
24597FO		75		0.164	0.200
24595FO		50		0.149	0.200
24201FO		100		0.178	0.200
24207FO		75		0.171	0.200
24205FO		50		0.154	0.200

*Calculated as 4 percent of the PSD Class I Increment

Table 5

ISCST3 Model Predicted SO_2 Concentrations for Class I SILs at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
3951FO	3-Hour	100	1988	**1.117**	1.000
3957FO		75		**1.009**	1.000
3955FO		50		0.873	1.000
3591FO		100		**1.201**	1.000
3597FO		75		**1.087**	1.000
3595FO		50		0.938	1.000
3201FO		100		**1.252**	1.000
3207FO		75		**1.136**	1.000
3205FO		50		0.978	1.000
24951FO	24-Hour	100		**0.212**	0.200
24957FO		75		0.194	0.200
24955FO		50		0.168	0.200
24591FO		100		**0.227**	0.200
24597FO		75		**0.208**	0.200
24595FO		50		0.181	0.200
24201FO		100		**0.236**	0.200
24207FO		75		**0.217**	0.200
24205FO		50		0.189	0.200

*Calculated as 4 percent of the PSD Class I Increment

Table 6

ISCST3 Model Predicted 3-Hour SO_2 Concentrations for Class I Increment Analysis at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)
3591FO	3-Hour	100	1984	**28.7**	25.0
3201FO		100		**28.7**	25.0
3207FO		75		**28.7**	25.0
3951FO		100	1985	23.1	25.0
3957FO		75		23.1	25.0
3955FO		50		23.1	25.0
3591FO		100		23.1	25.0
3597FO		75		23.1	25.0
3201FO		100		23.2	25.0
3207FO		75		23.1	25.0
3205FO		50		23.1	25.0
3951FO		100	1986	21.7	25.0
3957FO		75		21.7	25.0
3955FO		50		21.7	25.0
3591FO		100		21.7	25.0
3597FO		75		21.7	25.0
3595FO		50		21.7	25.0
3201FO		100		21.8	25.0
3207FO		75		21.7	25.0
3205FO		50		21.7	25.0
3951FO		100	1987	**25.6**	25.0
3957FO		75		**25.6**	25.0
3955FO		50		**25.6**	25.0
3591FO		100		**25.6**	25.0
3597FO		75		**25.6**	25.0
3595FO		50		**25.6**	25.0
3201FO		100		**25.6**	25.0
3207FO		75		**25.6**	25.0
3205FO		50		**25.6**	25.0
3951FO		100	1988	23.5	25.0
3957FO		75		23.5	25.0
3591FO		100		23.5	25.0
3597FO		75		23.5	25.0
3201FO		100		23.5	25.0
3207FO		75		23.5	25.0

Table 7

ISCST3 Model Predicted 24-Hour SO_2 Concentrations for Class I Increment Analysis at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)
24201FO	24-Hour	100	1986	**5.2**	5.0
24951FO		100	1988	**7.1**	5.0
24591FO		100		**7.1**	5.0
24597FO		75		**7.1**	5.0
24201FO		100		**7.1**	5.0
24207FO		75		**7.1**	5.0

Table 8

JEA Brandy Branch CT Contributions to
ISCST3 Model Predicted 3-Hour SO_2 Concentrations
at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Date/Hrs	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
3591FO	3-Hour	100	1984	1-24/10-12	0.00007	25.0	1.00
3201FO		100			0.00007	25.0	1.00
3207FO		75			0.00007	25.0	1.00
3591FO		100		7-4/7-9	0.00026	25.0	1.00
3201FO		100			0.00026	25.0	1.00
3207FO		75			0.00026	25.0	1.00
3951FO		100	1987	3-30/1-3	0.00032	25.0	1.00
3957FO		75			0.00032	25.0	1.00
3955FO		50			0.00032	25.0	1.00
3591FO		100			0.00032	25.0	1.00
3597FO		75			0.00032	25.0	1.00
3595FO		50			0.00032	25.0	1.00
3201FO		100			0.00032	25.0	1.00
3207FO		75			0.00032	25.0	1.00
3205FO		50			0.00032	25.0	1.00
3951FO		100		6-22/7-9	0.00031	25.0	1.00
3957FO		75			0.00031	25.0	1.00
3955FO		50			0.00031	25.0	1.00
3591FO		100			0.00031	25.0	1.00
3597FO		75			0.00031	25.0	1.00
3595FO		50			0.00031	25.0	1.00
3201FO		100			0.00031	25.0	1.00
3207FO		75			0.00031	25.0	1.00
3205FO		50			0.00031	25.0	1.00

Table 9

JEA Brandy Branch CT Contributions to
ISCST3 Model Predicted 24-Hour SO_2 Concentrations
at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Date/Hrs	Receptor*	Maximum Predicted Conc. (μg/m^3)	Class I Increment (μg/m^3)	Class I SIL** (μg/m^3)
24201FO	24-Hour	100	1986	10-25/24	3	0.026	5.0	0.20
24951FO		100	1988	3-25/24	3	0.087	5.0	0.20
24591FO		100			3	0.092	5.0	0.20
24597FO		75			3	0.089	5.0	0.20
24201FO		100			3	0.095	5.0	0.20
24207FO		75			3	0.092	5.0	0.20
24951FO		100		4-3/24	4	0.090	5.0	0.20
24591FO		100			4	0.096	5.0	0.20
24597FO		75			4	0.088	5.0	0.20
24201FO		100			4	0.100	5.0	0.20
24207FO		75			4	0.092	5.0	0.20
24951FO		100		6-7/24	1	0.034	5.0	0.20
					2	0.003	5.0	0.20
					3	0.003	5.0	0.20
					4	0.002	5.0	0.20
24591FO		100			1	0.038	5.0	0.20
					2	0.003	5.0	0.20
					3	0.003	5.0	0.20
					4	0.002	5.0	0.20
24597FO		75			1	0.031	5.0	0.20
					2	0.003	5.0	0.20
					3	0.004	5.0	0.20
					4	0.002	5.0	0.20
24201FO		100			1	0.040	5.0	0.20
					2	0.003	5.0	0.20
					3	0.004	5.0	0.20
					4	0.002	5.0	0.20
24207FO		75			1	0.033	5.0	0.20
					2	0.003	5.0	0.20
					3	0.004	5.0	0.20
					4	0.002	5.0	0.20

*Receptor locations in UTM coordinates

1	383000	3384000
2	378000	3382000
3	374000	3383000
4	370000	3383000

**Calculated as 4 percent of the PSD Class I Increment

Table 9 (Cont.)

JEA Brandy Branch CT Contributions to
ISCST3 Model Predicted 24-Hour SO_2 Concentrations
at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Date/Hrs	Receptor*	Maximum Predicted Conc. (μg/m^3)	Class I Increment (μg/m^3)	Class I SIL** (μg/m^3)
24951FO	24-Hour	100	1988	7-3/24	4	0.046	5.0	0.20
24591FO		100			4	0.050	5.0	0.20
24597FO		75			4	0.045	5.0	0.20
24201FO		100			4	0.052	5.0	0.20
24207FO		75			4	0.047	5.0	0.20
24951FO		100		9-3/24	1	0.034	5.0	0.20
					3	0.042	5.0	0.20
					4	0.022	5.0	0.20
24591FO		100			1	0.037	5.0	0.20
					3	0.046	5.0	0.20
					4	0.025	5.0	0.20
24597FO		75			1	0.032	5.0	0.20
					3	0.040	5.0	0.20
					4	0.020	5.0	0.20
24201FO		100			1	0.039	5.0	0.20
					3	0.048	5.0	0.20
					4	0.026	5.0	0.20
24207FO		75			1	0.034	5.0	0.20
					3	0.042	5.0	0.20
					4	0.021	5.0	0.20
24951FO		100		9-9/24	1	0.083	5.0	0.20
24591FO		100			1	0.088	5.0	0.20
24597FO		75			1	0.084	5.0	0.20
24201FO		100			1	0.091	5.0	0.20
24207FO		75			1	0.087	5.0	0.20
24951FO		100		11-26/24	1	0.001	5.0	0.20
					2	0.084	5.0	0.20
24591FO		100			1	0.001	5.0	0.20
					2	0.090	5.0	0.20
24597FO		75			1	0.001	5.0	0.20
					2	0.082	5.0	0.20
24201FO		100			1	0.001	5.0	0.20
					2	0.094	5.0	0.20
24207FO		75			1	0.001	5.0	0.20
					2	0.085	5.0	0.20

*Receptor locations in UTM coordinates

1	383000	3384000
2	378000	3382000
3	374000	3383000
4	370000	3383000

**Calculated as 4 percent of the PSD Class I Increment

Attachment A

Enveloped Emissions Spreadsheet

JEA 60903.0030
Jacksonville, Florida
Enveloped Stack Parameters

4000 Hours of natural gas simple cycle operation per year
800 Hous of fuel oil simple cycle operation per year

Last Revised 03/05/99
Date Printed 08/03/99 12:40 PM

NATURAL GAS OPERATION — 100 Percent

Load: 100 Percent; Turbine: PG7241 (FA); Ambient Temperature (F)	95	59	20	SHORT TERM: Representativa* 100 Pecent Load		ANNUALIZED (d): 59 Degrees 100 Pecent Load	
Exit Velocity (ft/s)	148	157	164.0	148 ft/s	45.04 m/s	156.75 ft/s	47.78 ft/s
Exit Temp (F)	1144	1116	1081	1081 F	855.93 K	1116.00 F	875.37 K
Emissions (lb/h)							
NOx (f)	71.20	79.20	84.80	85 lb/h	10.68 g/s	36.16 lb/h	4.56 g/s
CO	43.00	48.00	52.00	52 lb/h	6.55 g/s	21.92 lb/h	2.76 g/s
SO2 (a)	0.97	1.07	1.14	1 lb/h	0.14 g/s	0.49 lb/h	0.06 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	2.60	2.80	3.00	3 lb/h	0.38 g/s	1.28 lb/h	0.16 g/s

FUEL OIL OPERATION — 100 Percent

Load: 100 Percent; Turbine: PG7241 (FA); Ambient Temperature (F)	95	59	20	SHORT TERM: Representative* 100 Pecent Load		ANNUALIZED (d): 59 Degrees 100 Pecent Load		Total Annual Dual Fuel Parameters (e): 100 Pecent Load	
Exit Velocity (ft/s)	152	162	168.04	152 ft/s	46.27 m/s	161.60 ft/s	49.26 m/s	156.75 ft/s	47.78 m/s
Exit Temp (F)	1133	1098	1068	1068 F	848.71 K	1098.00 F	865.37 K	1116.00 F	875.37 K
Emissions (lb/h)									
NOx (f)	286.00	318.00	338.00	338 lb/h	42.59 g/s	29.04 lb/h	3.68 g/s	65.21 lb/h	8.22 g/s
CO	59.00	65.00	69.00	69 lb/h	8.69 g/s	5.94 lb/h	0.75 g/s	27.85 lb/h	3.51 g/s
SO2 (a)	88.38	98.21	104.30	104 lb/h	13.14 g/s	8.97 lb/h	1.13 g/s	9.46 lb/h	1.19 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.80	3.00	3.00	3 lb/h	0.38 g/s	0.27 lb/h	0.03 g/s	1.55 lb/h	0.20 g/s

NATURAL GAS OPERATION — 75 Percent

Load: 75 Percent; Turbine: PG7241 (FA); Ambient Temperature (F)	95	59	20	SHORT TERM: Representative 75 Pecent Load		ANNUALIZED (d): 59 Degrees 75 Pecent Load	
Exit Velocity (ft/s)	124	130	133	124 ft/s	37.85 m/s	129.71 ft/s	39.54 m/s
Exit Temp (F)	1170	1139	1112	1112 F	873.15 K	1139.00 F	888.15 K
Emissions (lb/h)							
NOx (f)	58.40	63.20	67.20	67 lb/h	8.47 g/s	28.86 lb/h	3.64 g/s
CO	36.00	39.00	41.00	41 lb/h	5.17 g/s	17.81 lb/h	2.24 g/s
SO2 (a)	1	0.86	0.92	1 lb/h	0.12 g/s	0.39 lb/h	0.05 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	2.20	2	2	2 lb/h	0.30 g/s	1.00 lb/h	0.13 g/s

FUEL OIL OPERATION — 75 Percent

Load: 75 Percent; Turbine: PG7241 (FA); Ambient Temperature (F)	95	59	20	SHORT TERM: Representative 75 Pecent Load		ANNUALIZED (d): 59 Degrees 75 Pecent Load		Total Annual Dual Fuel Parameters (e): 75 Pecent Load	
Exit Velocity (ft/s)	126.43	132	135	126 ft/s	38.54 m/s	131.67 ft/s	40.13 m/s	129.71 ft/s	39.54 m/s
Exit Temp (F)	1200	1194	1183	1183 F	912.59 K	1194.00 F	918.71 K	1139.00 F	888.15 K
Emissions (lb/h)									
NOx (f)	232.00	256.00	271.00	271 lb/h	34.14 g/s	23.38 lb/h	2.95 g/s	52.24 lb/h	6.58 g/s
CO	47.00	50.00	51.00	51 lb/h	6.43 g/s	4.57 lb/h	0.58 g/s	22.37 lb/h	2.82 g/s
SO2 (a)	72.32	79.69	84.44	84 lb/h	10.64 g/s	7.28 lb/h	0.92 g/s	7.67 lb/h	0.97 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.20	2	2	2 lb/h	0.30 g/s	0.20 lb/h	0.03 g/s	1.21 lb/h	0.15 g/s

NATURAL GAS OPERATION — 50 Percent

Load: 50 Percent; Turbine: PG7241 (FA); Ambient Temperature (F)	95	59	20	SHORT TERM: Representative 50 Pecent Load		ANNUALIZED (d): 59 Degrees 50 Pecent Load	
Exit Velocity (ft/s)	106	111	113	106 ft/s	32.42 m/s	110.53 ft/s	33.69 m/s
Exit Temp (F)	1200	1164	1160	1160 F	899.82 K	1164.00 F	913.15 K
Emissions (lb/h)							
NOx (f)	46.40	50.40	52.80	53 lb/h	6.65 g/s	23.01 lb/h	2.90 g/s
CO	30.00	33.00	34.00	34 lb/h	4.28 g/s	15.07 lb/h	1.90 g/s
SO2 (a)	1	1	1	1 lb/h	0.09 g/s	0.32 lb/h	0.04 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.82 lb/h	0.10 g/s

FUEL OIL OPERATION — 50 Percent

Load: 50 Percent; Turbine: PG7241 (FA); Ambient Temperature (F)	95	59	20	SHORT TERM: Representative 50 Pecent Load		ANNUALIZED (d): 59 Degrees 50 Pecent Load		Total Annual Dual Fuel Parameters (e): 50 Pecent Load	
Exit Velocity (ft/s)	108.45	112	113	108 ft/s	33.06 m/s	112.04 ft/s	34.15 m/s	110.53 ft/s	33.69 m/s
Exit Temp (F)	1200	1200	1200	1200 F	922.04 K	1200.00 F	922.04 K	1184.00 F	913.15 K
Emissions (lb/h)									
NOx (f)	182.00	199.00	209.00	209 lb/h	26.33 g/s	18.17 lb/h	2.29 g/s	41.19 lb/h	5.19 g/s
CO	74.00	63.00	57.00	74 lb/h	9.32 g/s	5.75 lb/h	0.72 g/s	20.82 lb/h	2.62 g/s
SO2 (a)	57.30	62.70	65.90	66 lb/h	8.30 g/s	5.73 lb/h	0.72 g/s	6.04 lb/h	0.76 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.68 lb/h	0.71 g/s
VOC (c)	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.16 lb/h	0.02 g/s	0.99 lb/h	0.12 g/s

NOTE:

(a) SO2 values were calculated based on 0.2 gr/100 scf in the natural gas and #2 distillate fuel oil (0.05% sulfur)
Example Calculations:
Natural gas 100 percent load at 95F = (1,468.9 MBtu/hr)*(lb/23.8 ft^3)*(20,675 Btu/lb)*(0.2gr/100scf)*(1lb/7000gr)*(64SO2/32S)*(10^6Btu/MBtu) = 0.97 lb/hr.
#2 Dist. Fuel Oil 100 percent load @ 95F = (0.05lb S/100lb fuel)*(64 lb SO2/32 lb S)*(7.05 lb fuel/1gal)*(1gal/7.05 lb)*(lb/ 18,550 Btu)*(1,639.4 MBtu/hr)*(10^6 BTU/MBtu) = 88.38 lb/hr.

(b) PM emission values are for front half filterable emissions only.

(c) VOC emissions represent 20% of the UHC emissions.

(d) Annualized emission rate based on specific number of hours of Natural Gas and Fuel Oil operation.

(e) Exit Velocity and Exit Temperature values are from the annualized natural gas operating scenarios.
The emission rate values are annualized @ 59 F based on the number of hour of fuel specific firing.

(f) NOx emission values for natural gas firing are at 12 ppm and 42 ppm for fuel oil firing.

Modeling File Description

Included with the write-up for the additional Okefenokee SO_2 Increment analysis are two computer diskettes. These two diskettes contain the modeling files used in the Increment analysis.

Diskette one contains the first Class I SIL analysis in the folder titled "Okefenokee SIL Analysis". This folder contains the files for the five years modeled in the SIL analysis. Also, included on the first diskette is the Class I Increment analysis in the folder titled "Okefenokee Increment Analysis". This folder contains the files for the five years modeled in the Increment analysis.

Diskette two contains the second Class I SIL analysis in the folder titled "Okefenokee 2^{nd} SIL Analysis". This folder contains two zip files (24-hour and 3-hour). These two subfolders contain the files used to determine if the Brandy Branch Project was a significant contributor to modeled Increment exceedances. Also, included on the second diskette is the meteorological data folder "metdata", which contains the data set used to run the ISCST3 model.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 29-Jul-1999 02:04pm
From: Mike Halpin TAL 850/488-0114
HALPIN_M@A1
Dept:
Tel No:

Subject: JEA Brandy Branch

Al / Teresa -

Here's the (unscrubbed) numbers for comparing the Southside Station's emissions to Brandy Branch (numbers are in TPY):

	SOUTHSIDE STATION			
	'97/98	'98/'99	BRANDY BRANCH	Difference
TOTAL SO2 (TONS)	902.3	1224.8	124.3	(778)
TOTAL NOx (TONS)	735.5	852.1	857.7	122
TOTAL PM (TONS)	74.9	100.1	74.5	(0.4)
TOTAL CO (TONS)	54.2	63.0	366.2	312

The "Difference" column compares the '97/'98 data (as it is more conservative), but even so I believe that this helps in our efforts to describe our current "Intent to Issue" plans. We're looking at net reductions in PM and SO2, with net NOx values that nearly clear the PSD Significance Level hurdle (and likely do if we look at '98/'99 data).

I have asked Bert if they would be willing to accept a 0.04%S content limit in their oil, if we were agreeable to a liberal averaging period. This will help even more towards mitigating the regional haze issue.

Let me know your thoughts on all of this.

Al - Are you drafting the Intent to Issue? I can put some of this in there if you'd like me to take a shot at starting it.

Mike

SOUTHSIDE GENERATING STATION

UNIT #4	1993	1994	1995	1996	1997	1998
GAS BURNED (KCF)	148,883	47,214	21,104	97,903	235,079	445,007
BTU/FT3	1,045	1,046	1,048	1,052	1,054	1,059
OIL BURNED (BBL)	15,821	24,880	-	15,858	1,551	128,515
% SULFUR	1.00	0.98	0.98	0.98	0.91	0.98
BTU/BBL	6,324,394	6,371,392	6,351,470	6,390,942	6,400,606	6,353,133
UNIT #5						
GAS BURNED (KCF)	1,069,301	952,476	1,536,930	608,681	947,953	850,228
BTU/FT3	1,042	1,046	1,048	1,051	1,055	1,060
OIL BURNED (BBL)	208,328	110,024	11,050	84,090	89,625	341,468
% SULFUR	0.99	0.98	0.98	0.98	0.95	0.98
BTU/BBL	6,336,048	6,367,616	6,351,470	6,387,219	6,395,450	6,359,145
TOTAL MBTU	2,689,829	1,904,787	1,703,003	1,381,166	1,830,983	4,360,422

Site oil consumption (BBLS)	224,149	134,904	11,050	99,948	91,176	469,983
Site oil consumption (MBTU)	1,420,034	859,111	70,184	638,449	583,120	2,987,917
Site oil SO2 emissions (TPY)	710.0	429.6	35.1	319.2	291.6	1494.0
Site gas SO2 emissions (TPY)	0.35	0.29	0.45	0.20	0.34	0.37
Average oil SO2 emissions (TPY)	Oil	Gas				
6 year average	546.6	0.3				
5 year average	513.9	0.3				
4 year average	535.0	0.3				
3 year average	701.6	0.3				
2 year average	892.8	0.4				

Brandy Branch SO2 emissions TPY	
800 hours per year oil / 4000 gas	124.3
750 hours per year oil / 4000 gas	116.9

RECIEVED 7-21-99

g

GE Energy Services

Marvin V. Sindel Jr.
Sales Manager

GE Energy Services Sales
General Electric International, Inc.
10 Van Dyck Rd. Jacksonville, FL. 32218
*Tel: 904-757-2620, Dial Comm: 8*585-2620*
Fx: 904-757-2652
Email: marvin.sindel@ps.ge.com

1/28/99

Subject: GE Frame 7FA Gas Turbine NOx Guarantee for JEA

Mr. Jim Connolly, P.E.
JEA
21 West Church Street
Jacksonville, FL. 32202

Dear Jim,

Pursuant to your question on the NOx emission guarantee for the three GE Frame 7FA units that JEA has purchased to be installed at the Brandy Branch Station, the following information is offered:

1. The GE guarantee for the units purchased is 15 ppm NOx. GE will guarantee this level only for the "new and clean" test performed immediately after the installation of the unit is complete. This guarantee is similar to GE guaranteeing the performance of the unit at the "new and clean" condition.

2. The unit will operate at the 15 ppm level only for load conditions above 50% load. Should JEA use the units in their peaking mode for load control and operate the unit below this load point, the NOx level will exceed the 15 ppm .

3. The current NOx guarantee is for 15 ppm. However, with some additional modifications, GE is able to offer an improved guarantee of 9 ppm NOx. The price adder to change the contractual guarantee to 9 ppm NOx is $300,000.00 per unit.

I hope this answers your questions concerning the GE units contractual guarantee concerning NOx emissions. Should you have any further questions regarding the GE units, please contact me at your convenience.

Respectfully,

DEPARTMENT OF
ENVIRONMENTAL PROTECTION
JUL 21 1999
SITING COORDINATION

Marvin Sindel
Sales Manager

cc: J. Grassman - GE Schenectady

g

GE Power Systems

Marvin V. Sindel Jr.
Sales Manager

GE Power Systems Sales
10 Van Dyck Rd. Jacksonville, FL 32218
Tel: 904-757-2620, Dial Comm: 8*585-2620
_Fx: 904-757-2652_
Email: marvin.sindel@ps.ge.com

2/10/99

Subject: GE/JEA Agreement on 9 ppm NOx for Brandy Station Gas Turbines

Mr. Jim Connolly
JEA
21 West Church Street
Jacksonville, FL. 32202

Dear Jim

GE has agreed to the following offer to JEA:

Modification of the 3 Gas Turbines to be installed at the Brandy Branch Station to allow for 9 ppm NOx operation on gas, pursuant to our limitations at partial load of maintaining NOx levels. The unit at Kennedy Station will not be modified to this lower NOx level guarantee.

In return JEA will allow GE to modify the shipping schedule for the 3rd unit at Brandy Branch (this is the final unit of the 4 gas turbines JEA has purchased) from a January 2001 date to a March 2001 date.

The guarantees and liquidated damages of the contract will be modified to reflect the new guarantee of 9ppm NOx at full load on gas and the shipment of the final gas turbine to March 2001.

Please confirm in writing JEA's acceptance of this offer. Should you have any questions, please contact me at your convenience.

GE-JEA-04

Respectfully,

Marv Sindel

Date Received: 2/10/99
Project/WRN: 60903
Title: 9 PPM NOx AGREEMENT
File(s) 63.1003

Name	Action	Info

Keywords NOx, AIR EMISSIONS

BLACK & VEATCH
JEA Tower, 21 West Church Street, Tower 10, Jacksonville, Florida 32202-3139, (904) 665-7446

JEA
Kennedy/Brandy Branch Combustion Turbine Project

B&V Project 29686/60903
B&V File 62.1003/14.0200
February 26, 1999

Subject: Conformed Specification – Rev. 4

General Electric Co.
1 River Road, Building 23, Room 211
Schenectady, New York 12345

Attention: Mr. J. T. Grassmann
Project Manager

Dear Mr. Grassmann:

The combustion turbine generator (CTG) conformed specifications for the JEA Kennedy and Brandy Branch projects have been revised to incorporate the following changes.

- Ref.: GE Letter dated 2/10/99 from Marv Sindel to Jim Connolly.
  JEA E-mail dated 2/11/99 from Jim Connolly to Marv Sindel.
  Change NOx guarantee on natural gas for 3 units for Brandy Branch from 15 to 9 ppmvd @ 15% O2 in exchange for delaying schedule for 4th unit by 2 months.
- Ref.: GE E-mail dated 2/16/99 from John Almstead to Rick Tetzloff.
  Provided estimated (not guaranteed) starting times.

The following sections have been revised and 9 copies are enclosed.

- <u>Section IV – General Conditions</u>. Termination payment schedule and invoicing and payment terms schedule revised for 2 month delay for 4th unit.
- <u>Section V – Special Conditions</u>. Payment schedule revised for 2 month delay for 4th unit.
- <u>Section VI, Subsection 1.1 – General Description and Scope of the Work</u>. Delivery and operation of the unit schedules revised for 2 month delay for 4th unit.
- <u>Attachment 1 – Technical Data Sheets</u>. NOx emissions revised to state that the Kennedy unit is guaranteed for 15 ppm and that the Brandy Branch units are guaranteed for 9 ppm. Added starting times to data sheets and changed "guaranteed" to "estimated".

New text is shown with underlining and deleted text is shown with strikethrough. Lines that contain revisions have a vertical line in the margin. If you have any questions, please let us know.

Very truly yours,

BLACK & VEATCH CORP.

Rick Tetzloff, P.E.

General Electric Co.
Mr. J. T. Grassmann

B&V Project 29686/60903
February 26, 1999

rct

cc : (all with attachment)
Marv Sindel, GE
Jim Connolly, JEA
Eddie Mims, JEA (3 copies)
Dave Larson, FD
Gene Bergt, B&V
Dale Isley, B&V
Dick Ward, B&V
Ken Weiss, B&V

SECTION IV - GENERAL CONDITIONS

TABLE OF CONTENTS

SECTION IV - GENERAL CONDITIONS

1. RESERVATIONS

1.1. The Jacksonville Electric Authority (JEA) reserves the right to cancel any Contract if there is a failure at any time to perform adequately the stipulations of the bid, and the conditions and specifications which are attached and made a part of this Contract, or in any case of any attempt to willfully impose upon JEA materials or products or workmanship which is, in the opinion of JEA, of an unacceptable quality. Any action taken in pursuance of this latter stipulation shall not affect or impair any rights or claim of JEA to damages for the breach of the Contract.

1.2. Should the Contractor fail to comply with the conditions of this Contract or fail to complete the required work or furnish the required materials within the time stipulated in the Contract, JEA reserves the right to purchase in the open market, or to complete the required work, at the expense of the Contractor or by recourse to provisions of the faithful performance bond if such bond is required under the conditions of the bid.

1.3. Should the Contractor fail to furnish any item or items, or to complete the required work included in this Contract, JEA reserves the right to withdraw such items or required work from the operation of this Contract without incurring further liabilities on the part of JEA thereby.

1.4. All items furnished must be completely new and free from defects unless specified otherwise.

2. CANCELLATION

2.1. Termination for Convenience for the equipment shall be in accordance with the Termination Schedule under Tab 4 of the Commercial Volume of IPS70600.

2.2. JEA may terminate this contract at any time upon written notice to GE and payment of termination charges in accordance with the schedule. Title to any terminated gas turbine equipment shall remain with GE.

Termination Payment Schedule

Project Month	Calendar Month	Milestone	Unit 1 %	Unit 2 %	Unit 3 %	Unit 4 %
0	June'98	After Notice to Proceed	0.60%	0.00%	0.00%	
1st Month	July '98		2.25%	0.60%	0.20%	
2nd Month	Aug. '98		3.75%	1.50%	0.60%	
3rd Month	Sept. '98		5.25%	2.25%	1.50%	
4th Month	Oct. '98		7.50%	3.00%	2.25%	~~3.00%~~
5th Month	Nov. '98		10.00%	3.75%	3.00%	~~3.00%~~
6th Month	Dec. '98		12.75%	4.50%	3.75%	3.00%
7th Month	Jan. '99		15.50%	5.25%	4.50%	3.00%
8th Month	Feb. '99		18.00%	6.50%	5.25%	3.00%
9th Month	Mar. '99		20.75%	7.50%	6.00%	3.00%
10th Month	April '99		23.50%	10.00%	6.75%	3.00%
11th Month	May '99		26.50%	12.75%	7.50%	3.00%
12th Month	June '99		28.75%	15.50%	10.00%	3.00%
13th Month	July '99		31.50%	18.00%	12.75%	3.00%
14th Month	Aug. '99		34.00%	20.75%	15.50%	3.00%
15th Month	Sept. '99	Ship Unit 1	100%	23.50%	18.00%	3.00%
16th Month	Oct.-'99	Delivery Unit 1	100%	26.50%	20.75%	3.00%
17th Month	Nov.-'99			28.75%	23.50%	3.00%
18th Month	Dec.-'99			31.50%	26.50%	3.00%
19th Month	Jan.-'00			34.00%	28.75%	~~3.75~~ 3.00%
20th Month	Feb.-'00	Ship Unit 2		100%	31.50%	~~6.00~~ 3.00%
21st Month	Mar.-'00	Delivery Unit 2		100%	34.00%	~~10.00~~ 3.75%
22nd Month	Apr.-'00	Ship Unit 3			100%	~~12.75~~ 6.00%
23rd Month	May-'00	Delivery Unit 3			100%	~~15.50~~ 10.00%
24th Month	June-'00					~~18.00~~ 12.75%
25th Month	July-'00					~~20.75~~ 15.50%
26th Month	Aug.-'00					~~23.50~~ 18.00%
27th Month	Sept.-'00					~~26.50~~ 20.75%
28th Month	Oct.-'00					~~28.75~~ 23.50%
29th Month	Nov.-'00					~~31.50~~ 26.50%
30th Month	Dec.-'00					~~34.00~~ 28.75%
31st Month	Jan.-'01	~~Ship Unit 4~~				~~100.00~~ 31.50%
32nd Month	Feb.-'01	~~Delivery Unit 4~~				~~100.00~~ 34.00%
33rd Month	Mar.-'01	Ship Unit 4				100.00%
34th Month	Apr.-'01	Delivery Unit 4				100.00%

3. TAXES

3.1. The JEA is authorized to self-accrue the Florida Sales and Use Tax (Direct Payment Certificate Number TPP 0138) when purchasing tangible personal property without the payment of Florida sales and use tax to the supplier of such property.

3.2. Buyer shall be responsible for, and shall pay directly when due and payable, any and all Buyer Taxes (defined below), and all payments due and payable by Buyer to Seller hereunder shall be made in the full amount of the Contract Price, free and clear of all deductions and withholding, for Buyer Taxes.

3.3. "Buyer Taxes" means all taxes, duties, fees, or other charges of any nature (including, but not limited to, ad valorem, consumption, excise, franchise, gross receipts, license, property, sales, stamp, storage, transfer, turnover, use, or value-added taxes, and any and all items of withholding, deficiency, penalty, addition to tax, interest, or assessment related thereto), other than Seller Taxes, imposed by any governmental on Seller or its employees or subcontractors due to the execution of any agreement or the performance of or payment for work hereunder.

4. INVOICING AND PAYMENT TERMS

Payment Terms will be on a per unit basis in accordance with the following schedule.

	Unit 1	Unit2	Unit3	Unit 4
Receipt of Air Permit Information - June '98	10%	10%	10%	
July '98	4.2857%			
Aug. '98	4.2857%			
Sept. '98	4.2857%			
Oct. '98	4.2857%			10%
Nov. '98	4.2857%			
Dec. '98	4.2857%			
Jan. '99	4.2857%	4.2857%		
Feb. '99	4.2857%	4.2857%		
Mar. '99	4.2857%	4.2857%	4.2857%	
Apr. '99	4.2857%	4.2857%	4.2857%	
May. '99	4.2857%	4.2857%	4.2857%	
June '99	4.2857%	4.2857%	4.2857%	
July '99	4.2857%	4.2857%	4.2857%	
Aug. '99	4.2857%	4.2857%	4.2857%	
Sept. '99 CT Shipment - Unit 1	10%	4.2857%	4.2857%	
Oct. '99 30 Days After Shipment - Unit 1	10%	4.2857%	4.2857%	
Nov. '99		4.2857%	4.2857%	~~4.2857%~~
Dec. '99		4.2857%	4.2857%	~~4.2857%~~
Jan. '00		4.2857%	4.2857%	4.2857%
Feb. '00		4.2857%	4.2857%	4.2857%
Mar. '00 CT Shipment - Unit 2		10%	4.2857%	4.2857%
Apr. '00 30 Days After Shipment - Unit 2		10%	4.2857%	4.2857%
May '00 CT Shipment - Unit 3			10%	4.2857%
June '00 30 Days After Shipment - Unit 3			10%	4.2857%
July '00				4.2857%
Aug. '00				4.2857%
Sept. '00				4.2857%
Oct. '00				4.2857%
Nov. '00				4.2857%
Dec. '00				4.2857%
Jan. '01 ~~CT Shipment – Unit 4~~				~~10.00~~ 4.2857%
Feb. '01 ~~30 Days After Shipment – Unit 4~~				~~10.00~~ 4.2857%
Mar. '01 CT Shipment – Unit 4				10.00%
Apr. '01 30 Days After Shipment – Unit 4				10.00%
Successful Completion of Performance Tests - Each Unit	10%	10%	10%	10%

Payment Terms are Net 3 Days with wire transfer

Late Fee - 0.5% per day for days 3-15.

Or 1% per month thereafter

5. VALUE ENGINEERING

During the term of the Contract, JEA and Contractor are encouraged to identify ways to reduce the total cost to JEA of the supplies or services provided by the Contractor. JEA and Contractor may negotiate Contract amendments that support and allow such reductions in total costs including, but not limited to the sharing of savings resulting from implementation of cost-reducing initiatives between JEA and Contractor.

6. MINORITY BUSINESS ENTERPRISE SUBCONTRACTOR INITIATIVE

JEA encourages Contractor to employ firms certified as JEA Minority Business Enterprise ("MBE") firms as subContractors to the maximum extent practical. During the term of the Contract, JEA and Contractor may negotiate Contract amendments that support and allow the employment of such MBE firms by Contractor including, but not limited to changes in the price to JEA of the supplies or services supplied by the Contractor.

7. NON-DISCRIMINATION PROVISIONS

Contractor shall comply with:

7.1. The provisions of Presidential Order 11246, as amended and with all rules and regulations implementing that Executive Order and the portions of Executive Orders 11701 and 11758 as applicable to Equal Employment Opportunity. Said executive orders and all rules and regulations implementing same are by this reference incorporated herein as if set out in their entirety;

7.2. The provisions of Section 503 of the Rehabilitation Act of 1973, as amended and the Americans with Disabilities Act ("ADA") and with all rules and regulations implementing such Acts. Said Acts and all rules and regulations implementing same are by this reference incorporated herein as if set out in their entirety; and

7.3. The provisions of The Employment and Training of Veterans Act, 38 U.S.C. 4212 (formerly 2012), as amended, and with all rules and regulations implementing such Act. Said Act and all rules and regulations implementing same are by this reference incorporated herein as if set out in their entirety.

7.4. Contractor agrees that if any of the obligations of this Contract are to be performed by a Sub-Contractor, then the provisions of this Subsection shall be incorporated into and become a part of the subcontract.

8. OCCUPATIONAL SAFETY AND HEALTH WARRANTY

Contractor warrants that the products sold or service rendered to JEA shall conform to the standards and regulations promulgated by the U.S. Department of Labor under the Occupational Safety and Health Act of 1970 (29 U.S.C. 651, PL91-596). In the event the product sold does not conform to the OSHA Standards and/or regulations, JEA at its option may return the product for correction or replacement at Contractor's expense or return the product at Contractor's expense and cancel the Contract. Services performed by the Contractor which do not conform to the OSHA Standards and/or regulations JEA shall notify the Seller and Seller shall remedy the nonconformance as stipulated in the Warranty Subsection of General Conditions.

9. PROTECTION OF THE ENVIRONMENT

Contractor shall bear full responsibility for the transportation, use and disposal of any hazardous or toxic substance under the Contractor's control during the performance of the Contract.

10. SUBCONTRACTING OR ASSIGNING OF CONTRACT

The Contractor shall not subcontract or assign the Contract or any portion thereof without the written consent of JEA.

11. CONTRACT DOCUMENTS

The Contract shall consist of JEA's Contract or Purchase Order Form together with these specifications and conditions including the executed Bid Form which shall be collectively referred to as the Contract Documents. This Contract is the complete agreement between the Parties. Parol or extrinsic evidence will not be used to vary or contradict the express terms of this Contract.

12. COMPLIANCE WITH CODES

The Codes and Standards that will apply will be in accordance with Tab 9 "Codes and Standards" and Tab 11 "Technical Comments" of the Technical Volume of IPS70600.

13. APPLICABLE STATE LAW

The rights, obligations and remedies of the Parties as specified under this Contract will be interpreted and governed in all respects by the laws of the State of Florida. Should any provision of this Contract be determined by the courts to be illegal or in conflict with any law of the State of Florida, the validity of the remaining provisions will not be impaired.

14. VENUE

The venue of any legal action brought by or filed against JEA relating to any matter arising under this Contract shall be exclusively in that state or federal court, sitting in Duval County, Florida which has jurisdiction over such legal action.

15. PATENTS/COPYRIGHTS

For one dollar ($1.00) acknowledged to be included and paid for in the Contract Price and other good and valuable considerations, Contractor agrees as follows:

15.1. If the JEA notifies Contractor promptly of the receipt of any claim, does not take any position adverse to Contractor regarding such claim and gives Contractor information, assistance and exclusive authority to settle an defend the claim, then Contractor shall defend, indemnify, save harmless and pay any and all awards of damages assessed against JEA and its respective members, directors, officers, agents, and employees, or any of them, from and against liability or loss, including but not limited to any claims, judgments, court costs and attorneys' fees incurred in any claims, or any pretrial, trial or appellate proceedings on account of infringements of patents, copyrighted or uncopyrighted works, secret processes, trade secrets, patented or unpatented inventions, articles or appliances, materials, or allegations thereof, pertaining to the Work, or any part thereof, combinations thereof, processes therein or the use of any tools, materials or implements used by Contractor.

15.2. Contractor shall, at its own expense, procure for JEA the right to continue use of the Work, parts tools, implements and materials or combinations thereof, or processes used therein resulting from a suit or judgment on account of patent or copyright infringement, or threats thereof.

15.3. If, in any such suit or proceeding, a temporary restraining order or preliminary injunction is granted, Contractor shall make every reasonable effort, by giving a satisfactory bond or otherwise, to secure the suspension of such restraining order or temporary injunction.

15.4. If, in any such suit or proceeding, any part of the Work is held to constitute an infringement and its use is permanently enjoined, Contractor shall, at once, make every reasonable effort to secure for JEA a license, authorizing the continued use of the Work. If Contractor fails to secure such license for JEA, Contractor shall replace the Work with non-infringing Work, or modify the Work in a way satisfactory to JEA, so that the Work is non-infringing.

15.5. The above remedies are the sole and exclusive remedies for Patent or Copyright claims.

16. WARRANTY

16.1. Contractor warrants to JEA that the Equipment to be delivered hereunder shall be designed and fit for the purpose of generating electric power when operated in accordance with Contractor's specific operation instructions and, in the absence thereof, in accordance with generally accepted operation practices of the electric power producing industry and shall be free from defects in material, workmanship and title.

16.2. The foregoing warranties (except as to title) for each Unit shall apply to defects which appear during the Warranty Period.

16.3. If the Equipment delivered hereunder does not meet the above warranties, JEA shall promptly notify Contractor in writing and make the Equipment available promptly for correction. Contractor shall thereupon correct any defect by, at its option, (i) repairing the defective Equipment or (ii) by making available necessary replacement parts FOB factory, freight prepaid to the Facility. Contractor shall provide technical advisory services reasonably necessary for such repair of the equipment including without limitation, transportation expenses of equipment and personnel to and from the jobsite, in and out expenses for Contractor's equipment, and customary expenses incidental thereto.

Installation costs, including craft labor, supervision and tools to effect the warranty repairs at the site are the responsibility of the Contractor. If a defect in the Equipment or part thereof cannot be corrected by Contractor's reasonable efforts, the Parties will negotiate an equitable adjustment in price with respect to such Equipment or part thereof.

Contractor will remove and replace all Contractor supplied equipment for the purpose of warranty repairs

16.4. Any reperformed service or repaired or replacement part furnished under this warranty shall carry warranties on the same terms as set forth above, except that the warranty period shall be for a period of one year from the date of such reperformance, repair or replacement. In any event the warranty period and Seller's responsibilities set forth herein for such repaired or replacement part shall terminate one year after the end of the Warranty Period applicable to the item of Equipment in which such repaired or replacement part was installed or in which such service was reperformed.

Warranty period will be one year from the date when the machine meets the minimum acceptable performance criteria, or two year from shipment, whichever occurs first. GE will not be responsible for the removal of any non GE supplied equipment.

The minimum acceptable performance criteria is defined as 95% of the output, and 105% of the heat rate guaranteed values.

16.5. Contractor does not warrant the Equipment or any repaired or replacement parts against normal wear and tear including that due to environment or operation, including excessive operation at peak capability, defined by a firing temperature higher than the base load design, operating outside of the manufacturer's recommendations, type of fuel, detrimental air inlet conditions or erosion, corrosion or material deposits from fluids. The warranties and remedies set forth herein are further conditioned upon (i) the proper storage, installation, operation, and maintenance of the Equipment and conformance with the operation instruction manuals (including revisions thereto) provided by Seller and/or its subcontractors, as applicable and (ii) repair or modification pursuant to Seller's instructions or approval. JEA shall keep proper records of operation and maintenance during the Warranty Period. These records shall be kept in the form of logsheets and copies shall be submitted to Contractor upon its request. Contractor does not warrant any equipment or services of others designated by JEA where such equipment or services are not normally supplied by Contractor.

Contractor recognizes that the machine will be operated under the following conditions:

200 Starts per year
400 hours operation on natural gas
100 hours operation on fuel oil

16.6. The preceding paragraphs of this Subsection 16 set forth the exclusive remedies for all claims based on failure of or defect in the Equipment provided under this Contract or Unit performance, whether the failure or defect arises before or during the Warranty Period and whether a claim, however instituted, is based on contract, indemnity, warranty, tort (including negligence), strict liability or otherwise. The foregoing warranties are exclusive and are in lieu of all other warranties and guarantees whether written, oral, implied or statutory. NO IMPLIED STATUTORY WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY

17. LIMITATION OF LIABILITY

17.1. The total liability of Contractor, on all claims of any kind, whether in contract, warranty, tort (including negligence), strict liability, indemnity, or otherwise, arising out of the performance or breach of the Contract or use of any Equipment shall not exceed the Contract Price allocable to the Equipment giving rise to the claim. All liability under this Contract shall terminate four years after the Shipment Date of the Unit giving rise to the claim. Equipment is defined as the combustion turbine generator and all auxiliary equipment as defined in JEA IFB JXF-167-98.

17.2. In no event, whether as a result of breach of contract, warranty, tort (including negligence), strict liability, indemnity, or otherwise, shall Contractor or its subcontractors or suppliers be liable for loss of profit or revenues, loss of use of the Equipment or any associated equipment, cost of capital, cost of substitute equipment, facilities, services or replacement power, downtime costs, claims of JEA's customers for such damages, or for any special, consequential, incidental, indirect or exemplary damages,and, to the extent permissible by law, JEA shall indemnify Contractor against such claims of JEA's customers.

17.3. JEA covenants and agrees that in the event it seeks to transfer or assign the Equipment and Services to any third party that it shall, as a condition to such transfer or assignment, cause such third party to acknowledge and accept the restrictions and limitations afforded under this Contract for the benefit of the Contractor, including the provisions of this Article.

17.4. If Contractor furnishes JEA with advice or assistance concerning any products, systems or work which is not required pursuant to the Specification, the furnishing of such advice or assistance will not subject Contractor to any liability, whether in contract, indemnity, warranty, tort (including negligence), strict liability or otherwise.

17.5. For the purposes of this Subsection 17, the term "Contractor" shall mean Contractor, its affiliates, subcontractors and suppliers of any tier, and their respective agents and employees, whether individually or collectively.

17.6. The provisions of this Subsection 17 shall prevail over any conflicting or inconsistent provisions contained in any of the documents comprising this Contract, except to the extent that such provisions further restrict Contractor's liability.

18. EXCUSABLE DELAYS

18.1. Contractor shall not have any liability or be considered to be in breach or default of its obligations under this Contract to the extent that performance of such obligations is delayed or prevented, directly or indirectly, due to: (i) causes beyond its reasonable control; or (ii) acts of God, act (or failures to act) of governmental authorities, fires, severe weather conditions, earthquakes, strikes or other labor disturbances, floods, war (declared or undeclared), epidemics, civil unrest, riot, delays in transportation from abnormal causes, or (iii) acts (or omissions) of JEA including failure to promptly: (a) provide Contractor with information and approvals necessary to permit Contractor to proceed with work within a reasonable amount of time and without interruption, (b) comply with the terms of payment, or (c) provide Contractor with such evidence as Contractor may request that any export or import license or permit has been issued (if such is the responsibility of JEA), or (iv) shipment to storage under Article 4 or (v) inability on account of causes beyond the reasonable control of Contractor to obtain necessary materials, necessary components or services. Contractor shall notify JEA of any such delay. The date of delivery or of performance shall be extended for a period equal to the time lost by reason of delay, plus such additional time as may be reasonably necessary to overcome the effect of such excusable delay. Contractor shall notify JEA, as soon as practicable, of the revised Delivery Date. If Contractor is delayed by acts or omissions of JEA, or by the prerequisite work of JEA's other contractors or suppliers, Contractor shall also be entitled to an equitable price adjustment. Causes associated in (i), (ii), and (iii) will make the provisions of (iv) and (v) acceptable to the Owner.

18.2. If delay excused by this Subsection 18 extends for more than one hundred and twenty (120) days and the parties have not agreed upon a revised basis for continuing the work at the end of the delay, including adjustment of the price, JEA, upon thirty (30) days written notice, may terminate the order with respect to the undelivered Equipment to which title has not yet passed and any uncompleted Services, whereupon JEA shall promptly pay Contractor its termination charges as set forth in Tab 4 of the Commercial Volume of IPS70600.

19. TITLE

19.1. Passage of Title. Title to Equipment or materials to be shipped from within the United States shall pass to JEA when available for shipment from the manufacturer's factory. Notwithstanding passage of title, Contractor shall remain responsible for risk of loss to the Equipment and materials incorporated therein until delivered to the agreed point of delivery.

19.2. Shipment to Storage. If any part of the Equipment cannot be shipped to JEA when ready due to any cause not attributable to Contractor, Contractor may ship such Equipment to storage. If such Equipment is placed in storage, including storage at the facility where manufactured, the following conditions shall apply: (a) title shall thereupon pass to JEA if it had not already passed; (b) any amounts otherwise payable to Contractor upon delivery or shipment shall be payable upon presentation of Contractor's invoices and certification of cause for storage; (c) all expenses incurred by Contractor, such as for preparation for and placement into storage, handling, inspection, preservation, insurance, storage, removal charges and any taxes shall be payable by JEA upon submission of Contractor's invoices; and (d) when conditions permit and upon payment of all amounts due hereunder, Contractor shall resume delivery of the Equipment to the originally agreed point of delivery; and (e) Contractor shall bear risk of loss.

20. INDEMNIFICATION

In consideration of Ten Dollars ($10.00) receipt and sufficiency of which is hereby acknowledged, the CONTRACTOR shall hold harmless, indemnify, and defend JEA and Black & Vetch ,its Engineer against any claim, action, loss, damage, injury, liability, cost and expense of whatsoever kind or nature (including, but not by way of limitation, attorney's fees and court costs) arising out of or injury (whether mental or corporeal) to persons, including death, or damage to property, of third parties (other than JEA), arising out of or incidental to the negligent acts or omissions of the CONTRACTOR in the performance of this contract or work performed thereunder. In the event of joint negligence on the part of JEA and the CONTRACTOR, any loss shall be apportioned in accordance with the provisions of the Uniform Contribution Among Tortfeasors Act (s. 768.31, F.S.), as that Act exists on the effective date of this contract. For purposes of this Indemnification, the term "JEA" shall include its governing board, officers, employees, agents and assigns. This indemnification shall survive the term of this AGREEMENT.

21. DELIVERY

21.1. Contractor shall be responsible for delivery of equipment, FOB accessible rail siding if by rail, and FOB jobsite if by truck. Partial deliveries shall be permitted. Contractor Technical Representative will direct the offloading of the equipment. Contractor will assist in providing handling information prior to delivery.

21.2. Title to each piece of Equipment shall pass to the Owner when the Equipment is made available for shipment at the factory or when placed in mutually acceptable storage facilities. Transportation to site and risk of loss until delivery to the site shall be the responsibility of the Contractor.

SECTION V - SPECIAL CONDITIONS

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1. LIQUIDATED DAMAGES

1.1. If Contractor fails to complete the Work in accordance with the specified contract schedule, or if the equipment fails to meet capacity, emissions, net output or heat rate requirements, Contractor shall pay JEA Liquidated Damages in accordance with the following breakdown day for each and every calendar day, including Sundays and holidays, starting on the day following the specified completion date(s) until the date(s) the item(s) of Work is completed and accepted by JEA. Time is of the essence.

1.2. Contractor agrees that said daily sum is to be paid not as a penalty, but as compensation to JEA as a fixed and reasonable liquidated damages for losses which JEA will suffer because of such default, whether through increased administrative and engineering costs, interference with JEA's normal operations, other tangible and intangible costs, or otherwise, which costs will be impossible or impracticable to measure or ascertain with any reasonable specificity.

1.3. Liquidated damages may, at JEA's option, be deducted from any monies held by JEA which are otherwise payable to Contractor.

1.4. Contractor's responsibility for Liquidated Damages shall in no way relieve Contractor of any other contractual obligations.

1.5. The maximum liability of Contractor for payment of Liquidated Damages for schedule delay shall be an amount equal to 15% of the Contract price.

1.5.1 **Schedule** - The Contractor agrees to pay Liquidated Damages in the amount of $9,000 for each calendar day that expires after October 31, 1999, until all equipment necessary for the installation and operation of the unit as outlined in JEA IFB JXF-167-98 is delivered to the Kennedy Generating Station. The Contractor shall be assessed Liquidated Damages under these provisions to which the schedule delay is attributable to the Contractor's non-compliance with the scope of work included as part of this Contract.

1.5.1.1 The amount of Liquidated Damages shall increase to $24,000 for each calendar day that expires after November 30, 1999, until all equipment necessary for the installation and operation of the Unit, as outlined in JEA IFB JXF-167-98, is delivered to the Kennedy Generating Station.

1.5.1.2 The Contractor agrees to pay Liquidated Damages in the amount of $24,000 for each calendar day that expires after the Owner scheduled date for the achievement of the minimum performance criteria, provided that the initial performance test is conducted a minimum of 30 days prior to the scheduled date of achievement of the minimum performance criteria.

For any delays in meeting the Owner scheduled date for the achievement of the minimum performance criteria, due solely to failure of Contractor supplied equipment, or acts or omissions by the Contractor, the Contractor agrees to pay liquidated damages in the amount of $24,000 for each calendar day that expires after the Owner scheduled date for the achievement of the minimum performance criteria. The minimum performance criteria is defined as 95% of the output and 105% of the heat rate on the guarantee data sheets.

1.5.1.3 If an order is placed for additional units at the time of the award of the contract, the Contractor agrees to pay Liquidated Damages in the amount of $9,000, for schedule delay, for each calendar day that expires after the dates shown on the following schedule.

First Additional Unit	April 1, 2000
Second Additional Unit	June 1, 2000

If a letter of intent is placed for a third additional unit on or before September 10, 1998, the Contractor agrees to pay Liquidated Damages in the amount of $9,000, for schedule delay, for each calendar day that expires after February 28, 2001.

The amount of Liquidated Damages shall increase to $24,000 for each calendar day that expires after 30 days from the respective delivery dates for the additional units, until all equipment necessary for the installation and operation of the unit as outlined in JEA IFB JXF-167-98 is delivered to the agreed upon site.

The Contractor agrees to pay Liquidated Damages in the amount of $24,000 for each calendar day that expires after the Owner scheduled date for the achievement of the minimum performance criteria, provided that the initial performance test is conducted a minimum of 30 days prior to the scheduled date of achievement of the minimum performance criteria.

For any delays in meeting the Owner scheduled date for the achievement of the minimum performance criteria, due solely to failure of Contractor supplied equipment, or acts or omissions by the Contractor, the Contractor agrees to pay liquidated damages in the amount of $24,000 for each calendar day that expires after the Owner scheduled date for the achievement of the minimum performance criteria. The minimum performance criteria is defined as 95% of the output and 105% of the heat rate on the guarantee data sheets.

1.5.2 **Net Electric Capacity** - The Contractor agrees to pay Liquidated Damages in the amount of $520, for each net kW, on a per unit basis, corrected to site conditions, that the combustion turbine generator fails to meet the guaranteed net electrical capacity for the greater difference for natural gas or distillate fuel, as specified in Section VI, Subsection 2.1.7. These liquidated damages shall be in addition to the Schedule Liquidated Damages, but shall not be assessed unless the Contractor fails to perform corrective measures to meet the guarantees within 90 days of the initial performance test.

1.5.3 **Net Heat Rate** - The Contractor agrees to pay Liquidated Damages in the amount of $2,425, for each net Btu/kWh (LHV), on a per unit basis, corrected to design point, that the combustion turbine generator actual heat rate exceeds the guaranteed net heat rate for the greater difference for natural gas or distillate fuel, as specified in Section VI, Subsection 2.1.7. These liquidated damages shall be in addition to the Schedule Liquidated Damages, but shall not be assessed unless the Contractor fails to perform corrective measures to meet the guarantees within 90 days of the initial performance test.

1.5.4 The liability of the Contractor for payment of liquidated damages for performance (including net electrical capacity and heat rate) is limited to 20% of the contract price of the unit giving rise to the claim.

2. TESTING AND ACCEPTANCE

Contractor will provide technical assistance in the performing of the performance test however we are not responsible for the conducting of the test , operating personnel, issuance of reports, fuel, etc.

3. QUALITY ASSURANCE

Final inspection and testing of the system shall be completed by JEA's representative referred to hereafter as the Engineer.

4. SUBMITTALS

4.1. Bidder shall submit all the information outlined in Section VI, Attachment 1 - Technical Proposal Data, with the Technical Proposal. Failure to provide all information may result in rejection of the bid.

5. **Payment Schedule**

Payment Terms will be on a per unit basis in accordance with the following schedule.

	Unit 1	Unit2	Unit3	Unit 4
Receipt of Air Permit Information - June '98	10%	10%	10%	
July '98	4.2857%			
Aug. '98	4.2857%			
Sept. '98	4.2857%			
Oct. '98	4.2857%			10%
Nov. '98	4.2857%			
Dec. '98	4.2857%			
Jan. '99	4.2857%	4.2857%		
Feb. '99	4.2857%	4.2857%		
Mar. '99	4.2857%	4.2857%	4.2857%	
Apr. '99	4.2857%	4.2857%	4.2857%	
May. '99	4.2857%	4.2857%	4.2857%	
June '99	4.2857%	4.2857%	4.2857%	
July '99	4.2857%	4.2857%	4.2857%	
Aug. '99	4.2857%	4.2857%	4.2857%	
Sept. '99 CT Shipment - Unit 1	10%	4.2857%	4.2857%	
Oct. '99 30 Days After Shipment - Unit 1	10%	4.2857%	4.2857%	
Nov. '99		4.2857%	4.2857%	~~4.2857%~~
Dec. '99		4.2857%	4.2857%	~~4.2857%~~
Jan. '00		4.2857%	4.2857%	4.2857%
Feb. '00		4.2857%	4.2857%	4.2857%
Mar. '00 CT Shipment - Unit 2		10%	4.2857%	4.2857%
Apr. '00 30 Days After Shipment - Unit 2		10%	4.2857%	4.2857%
May '00 CT Shipment - Unit 3			10%	4.2857%
June '00 30 Days After Shipment - Unit 3			10%	4.2857%
July '00				4.2857%
Aug. '00				4.2857%
Sept. '00				4.2857%
Oct. '00				4.2857%
Nov. '00				4.2857%
Dec. '00				4.2857%
Jan. '01 ~~CT Shipment – Unit 4~~				~~10.00~~ 4.2857%
Feb. '01 ~~30 Days After Shipment – Unit 4~~				~~10.00~~ 4.2857%
Mar. '01 CT Shipment – Unit 4				10.00%
Apr. '01 30 Days After Shipment – Unit 4				10.00%
Successful Completion of Performance Tests - Each Unit	10%	10%	10%	10%

Payment Terms are Net 3 Days with wire transfer

Late Fee - 0.5% per day for days 3-15.

Or 1% per month thereafter

6. **LONG TERM COMBUSTION TURBINE SERVICE AGREEMENT**

If the Owner selects to enter into a Long Term Combustion Turbine Service Agreement with the Contractor, the terms and conditions of the agreement will be negotiated in a separate negotiation session after the award.

7. TURBINE ALLIANCE

7.1. The Turbine Alliance will be negotiated at the time the Owner decides to enter into this type of agreement.

7.2. Any existing long term service agreements for the combustion turbine(s) included in this specification would become part of this turbine alliance agreement.

7.3. Owner reserves the right to start negotiations within a two year date from the award of the Combustion Turbine purchase.

General Electric Company
(Bidder's Name)

Critical speeds	RPM	Mode
First critical	1060 / 1107	Lateral / Torsional
Second critical	1100 / 6098	Lateral / Torsional
Third critical	2250 / 7129	Lateral / Torsional
Fourth critical	2460	Lateral

Vibration amplitude, ips (bearing housings)	Turbine		Generator	
	Nominal	Startup	Nominal	Startup
Typical	.25			
Alarm	.5			
Trip	1.0			

Vibration amplitude, mils (shaft displacement)	Turbine		Generator	
	Nominal	Startup	Nominal	Startup
Typical	< 5 mils pk - pk			
Alarm	N/A			
Trip	N/A			

Combustion Turbine Unit Weights and Dimensions

Turbine engine weight, tons: 189 GT Base

Auxiliary skids	Length ft	Length in.	Width ft	Width in.	Height ft	Height in.	Weight tons
Name Water Wash	Mech Outline						10
Lube Oil							34
PEECC							21
LCI							5
BAC							2
CO_2							4
Demister							2
Cooling Fan							5
Fuel Forward							6
DC Link Reactor							.75

General Electric Company
(Bidder's Name)

Shipping weight, entire unit, tons		
	Piece	Weight, tons
Heaviest piece handled during erection	Generator	540,000
Heaviest piece handled during major overhaul	Turbine Rotor	94,000
Overall dimensions, including enclosures		
Length, ft	See Mechanical	
Width, ft	Outline Drawing	
Height, ft		

Component Descriptions

Starting system General description	See Proposal
Maximum number of starts allowed in a 1 hour period at maximum design temperature	3
Time required between start attempts	Must coast to < 15% speed
Minimum time between controlled shutdown and subsequent start	Time to coast to firing speed
Minimum time between unit trip and subsequent start attempt	Time to coast to firing speed
Electric starting motor	
Manufacturer	N/A
Model	N/A
Voltage	N/A
Horsepower	N/A
Speed, rpm	N/A
Service factor	N/A

	General Electric Company (Bidder's Name)	
Full load amperes	N/A	
Starting amperes	N/A	
Torque converter		
Type	N/A	
Manufacturer	N/A	
Rating	N/A	
Static starting system		
Manufacturer	GE	
Drive capacity, kVA	See One Line	
Transformer size, kVA/volts/phase	One Line KVA/ volts/ phase	

Mechanical Accessory Equipment

	On-Line	Off-Line
Compressor wash system		
Type	Skid Mounted	
Flow to combustion turbine, gpm	26	81
Water quality required	Per GEK 103623	
Type of detergent	Not applicable	
Quantity of detergent	Not applicable	
Duration of wash, min	As required	Approx. 60
Tank capacity, gal	2500	
Recommended cleaning frequency, operating hours	Environment	Dependent

Fire detection and protection	
Fire protection system	
Type	CO_2
Number of releases allowed before recharge	2
Cross zone protection	None

General Electric Company
(Bidder's Name)

Concentration maintained	34%
Time maintained	40 min
Multi Stage Inlet air filtration equipment	
Manufacturer	Braden or Equal
Type	2 Stage w/Coalesoer
Filter media material	Synthetic
Efficiency	Dust spot efficiency of 96%
Means of filter support	SS Frame
Typical number of hours of operation before replacement of filter	Pre filter 3 mos. Final filter 2 yrs.
Pressure drop for	
Clean conditions, in. H_2O	1.25"
End of media life, in. H_2O	Typical 1" pre filter 2.5 Final filter
Exhaust Stack height, ft.	100

Motors	kW	Volts	Phase	Enclosure	Quantity
Starting motor	N/A				
Main lube oil pump	75	480	3	TEFC	2
Emergency lube oil pump (dc)	15	125	1	TEFC	1
Lube oil reservoir exhauster	6	480	3	TEFC	2
Other motors					
Seee One Line					

1.5.3 Supplemental Performance Data. The following three-page table, designated C.5, shall be reproduced by the bidder as required to define the requested information for the following ambient temperatures and coincident relative humidities:

Temperature/Relative Humidity Points:	20° F/60 percent
	59° F/60 percent
	95° F/60 percent

Numbering sequence of the tables shall be as follows:

Table No.	Fuel	Ambient Conditions
1.5-1	Natural gas	20° F/60 percent RH
1.5-2	Natural gas	59° F/60 percent RH
1.5-3	Natural gas	95° F/60 percent RH
1.5-4	Fuel Oil	20°F/60 percent RH
1.5-5	Fuel Oil	59°F/60 percent RH
1.5.6	Fuel Oil	95°F/60 percent RH

Minimum load shall be defined as the minimum load at which the base load NOx emission concentrations are maintained.

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 1

Ambient Temperature/
Relative Humidity: 20 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = 20675 Btu/lb Fuel Oil = ___Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 15

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	14900	46600	93200	139900	186500
Auxiliary power, kW	608	608	608	608	608
Gross heat rate, Btu/kWh (LHV)	35375	15650	11520	9950	9310
Exhaust flow, lb/h	2714×10^3	2725×10^3	2741×10^3	3025×10^3	3800×10^3
Exhaust Temp., °F	647	787	1017	1112	1081
Inlet guide vane position, degrees	54	54	54	60.4	88
Fuel flow, lb/h	25495	35274	51932	67327	83980
Water injection flow lb/h	----------	----------	----------	----------	----------
Nitrogen oxides, ppmvd at 15 percent O_2	69	93	94	15(KGS) 9 (BB)	15(KGS) 9 (BB)
Nitrogen oxides, lb/h as NO_2	137	266	401	84(KGS)	105 (KGS)
Carbon monoxide, ppmvd	102	102	699	15	15
Carbon monoxide, lb/h	261	259	1759	41	52
Sulfur dioxide, ppmw	0	0	0	0	0
Sulfur dioxide, lb/h	0	0	1	1	1
TSP, lb/h (non-condensables only)	9	9	9	9	9
PM10, lb/h (non-condensables only)	9	9	9	9	9
TSP, lbm/h (excluding H_2SO_4, including other condensables)	18	18	18	18	18
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
H_2SO_4, lbm/h	0	0	0	0	0

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 1

Unburned hydrocarbon, ppmvw	128	25	182	7	7
Unburned hydrocarbon, lb/h	193	38	279	12	15
Volatile organic compounds, ppmvw	25.6	5	36.4	1.4	1.4
Volatile organic compounds, lb/h	38.6	7.6	55.8	2.4	3
Oxygen, vol %	17.54	16.11	13.85	12.57	12.54
Nitrogen, vol %	76.75	76.25	75.45	75	74.99
Carbon, vol %	1.59	2.25	3.3	3.89	3.9
Argon, vol %	.92	.91	.9	.89	.91
Water, vol %	3.21	4.49	6.5	7.65	7.67
Opacity, percent	5	5	5	5	5

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 2

Ambient Temperature/
Relative Humidity: 59 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = 20675 Btu/lb Fuel Oil = ______ Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 15

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	13900	43300	86600	129900	173200
Auxiliary power, kW	608	608	608	608	608
Gross heat rate, Btu/kWh (LHV)	36505	16080	11790	10120	9370
Exhaust flow, lb/h	2570×10^3	2530×10^3	2595×10^3	2890×10^3	3542×10^3
Exhaust Temp., °F	690	830	1060	1139	1116
Inlet guide vane position, degrees	54	54	54	61.8	88
Fuel flow, lb/h	24542	33678	49383	63584	78495
Water injection flow lb/h	-----	-----	-----	-----	-----
Nitrogen oxides, ppmvd at 15 percent O_2	67	59	89	15(KGS) 9 (BB)	15(KGS) 9 (BB)
Nitrogen oxides, lb/h as NO_2	127	161	361	79 (KGS)	99 (KGS)
Carbon monoxide, ppmvd	102	> 1000	647	15	15
Carbon monoxide, lb/h	246	2596	1533	39	48
Sulfur dioxide, ppmw	0	0	0	0	0
Sulfur dioxide, lb/h	0	0	1	1	1
TSP, lb/h (non-condensables only)	9	9	9	9	9
PM10, lb/h (non-condensables only)	9	9	9	9	9
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
H_2SO_4, lbm/h	0	0	0	0	0

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 2

Unburned hydrocarbon, ppmvw	103	479	145	7	7
Unburned hydrocarbon, lb/h	148	691	211	11	14
Volatile organic compounds, ppmvw	20.6	95.8	29	1.4	1.4
Volatile organic compounds, lb/h	29.6	138.2	42.2	2.2	2.8
Oxygen, vol %	17.34	15.92	13.68	12.51	12.38
Nitrogen, vol %	76.12	75.62	74.84	74.44	74.39
Carbon, vol %	1.6	2.26	3.3	3.84	3.9
Argon, vol %	.91	.91	.89	.9	.89
Water, vol %	4.03	5.29	7.29	8.32	8.44
Opacity, percent	5	5	5	5	5

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 3

Ambient Temperature/
Relative Humidity: 95 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = 20675 Btu/lb Fuel Oil = _______ Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 15

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	12000	37600	75200	112800	150400
Auxiliary power, kW	608	608	608	608	608
Gross heat rate, Btu/kWh (LHV)	40305	17360	12500	10690	9760
Exhaust flow, lb/h	2429×10^3	2438×10^3	2452×10^3	2691×10^3	3253×10^3
Exhaust Temp., °F	729	862	1078	1170	1144
Inlet guide vane position, degrees	54	54	54	61.6	88
Fuel flow, lb/h	23395	31570	45465	58321	70999
Water injection flow lb/h	-------	-------	--------	---------	-------
Nitrogen oxides, ppmvd at 15 percent O_2	53	45	65	15(KGS) 9 (BB)	15(KGS) 9 (BB)
Nitrogen oxides, lb/h as NO_2	97	115	243	73 (KGS)	89 (KGS)
Carbon monoxide, ppmvd	102	>1000	687	15	15
Carbon monoxide, lb/h	229	2129	1515	36	43
Sulfur dioxide, ppmw	0	0	0	0	0
Sulfur dioxide, lb/h	0	0	1	1	1
TSP, lb/h (non-condensables only)	9	9	9	9	9
PM10, lb/h (non-condensables only)	9	9	9	9	9
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	18	18	18	18	18
H_2SO_4, lbm/h	0	0	0	0	0

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 3

Unburned hydrocarbon, ppmvw	87	422	172	7	7
Unburned hydrocarbon, lb/h	118	581	239	11	13
Volatile organic compounds, ppmvw	17.4	84.4	34.4	1.4	1.4
Volatile organic compounds, lb/h	23.6	116.2	47.8	2.2	2.6
Oxygen, vol %	16.85	15.53	13.44	12.24	12.1
Nitrogen, vol %	74.33	73.88	73.17	72.76	72.71
Carbon, vol %	1.61	2.22	3.19	3.75	3.82
Argon, vol %	.89	.89	.87	.86	.87
Water, vol %	6.33	7.49	9.83	10.39	10.51
Opacity, percent	5	5	5	5	5

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 4

Ambient Temperature/
Relative Humidity: 20 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = ________ Btu/lb Fuel Oil = 18550 Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 42

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	15200	47600	95200	142900	190500
Auxiliary power, kW	1542	1542	1542	1542	1542
Gross heat rate, Btu/kWh (LHV)	34960	15590	12030	10480	10000
Exhaust flow, lb/h	$2717x10^3$	$2729x10^3$	$2806x10^3$	$3156x10^3$	$3947x10^3$
Exhaust Temp., °F	655	803	995	1058	1045
Inlet guide vane position, degrees	54	54	54	61.1	88
Fuel flow, lb/h	28646	40005	61741	80733	102695
Water injection flow lb/h	0	0	54260	87910	125980
Nitrogen oxides, ppmvd at 15 percent O_2	72	112	42	42	42
Nitrogen oxides, lb/h as NO_2	148	333	196	259	332
Carbon monoxide, ppmvd	>1000	428	124	38	20
Carbon monoxide, lb/h	2242	1096	315	108	70
Sulfur dioxide, ppmw	5	6	9	11	11
Sulfur dioxide, lb/h	27	38	59	77	98
TSP, lb/h (non-condensables only)	17	17	17	17	17
PM10, lb/h (non-condensables only)	17	17	17	17	17
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
H_2SO_4, lbm/h	3	4	6	8	10

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 4

Unburned hydrocarbon, ppmvw	157	52	14	7	7
Unburned hydrocarbon, lb/h	235	78	22	13	16
Volatile organic compounds, ppmvw	78.5	26	7	3.5	3.5
Volatile organic compounds, lb/h	117.5	39	11	6.5	8
Oxygen, vol %	17.65	16.22	13.24	11.78	11.45
Nitrogen, vol %	77.16	76.83	73.86	72.53	71.99
Carbon, vol %	2.1	3.01	4.49	5.24	5.36
Argon, vol %	.93	.92	.88	.86	.86
Water, vol %	2.17	3.03	7.53	9.59	10.35
Opacity, percent	20	20	20	20	20

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 5

Ambient Temperature/
Relative Humidity: 59 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = ________ Btu/lb Fuel Oil = 18550 Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 42

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	14600	45500	91000	136500	182000
Auxiliary power, kW	1542	1542	1542	1542	1542
Gross heat rate, Btu/kWh (LHV)	35280	15790	12200	10800	10010
Exhaust flow, lb/h	$2573x10^3$	$2585x10^3$	$2658x10^3$	$2820x10^3$	$3683x10^3$
Exhaust Temp., °F	700	852	1050	1191	1098
Inlet guide vane position, degrees	54	54	54	56.7	88
Fuel flow, lb/h	27768	38728	59849	79472	98210
Water injection flow lb/h	0	0	51810	89620	119690
Nitrogen oxides, ppmvd at 15 percent O_2	70	109	42	42	42
Nitrogen oxides, lb/h as NO_2	138	314	190	255	318
Carbon monoxide, ppmvd	> 1000	384	91	20	20
Carbon monoxide, lb/h	1910	925	217	49	65
Sulfur dioxide, ppmw	5	6	10	12	11
Sulfur dioxide, lb/h	26	37	57	75	93
TSP, lb/h (non-condensables only)	17	17	17	17	17
PM10, lb/h (non-condensables only)	17	17	17	17	17
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
H_2SO_4, lbm/h	3	4	6	8	10

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 5

Unburned hydrocarbon, ppmvw	134	44	12	7	7
Unburned hydrocarbon, lb/h	191	63	17	11	15
Volatile organic compounds, ppmvw	67	22	6	3.5	3.5
Volatile organic compounds, lb/h	95.5	31.5	8.5	5.5	7.5
Oxygen, vol %	17.43	15.97	12.94	10.71	11.09
Nitrogen, vol %	76.53	76.19	73.22	71.3	71.3
Carbon, vol %	2.13	3.06	4.58	5.74	5.48
Argon, vol %	.92	.92	.88	.85	.86
Water, vol %	2.99	3.87	8.39	11.41	11.28
Opacity, percent	20	20	20	20	20

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 6

Ambient Temperature/
Relative Humidity: 95 °F/ 60 percent

Manufacturer: GE

Barometric Pressure: 14.69 psia

Model No./Combustor: PG 7241 FA

Natural Gas: LHV = ________ Btu/lb   Fuel Oil = 18550 Btu/lb

Combustion System Type: Dry Low NO_x

NO_x Control Level: 42

Power Factor: 0.90 pf

	Minimum Load	25 Percent of Baseload	50 Percent of Baseload	75 Percent of Baseload	100 Percent of Baseload
Gross output, kW	12800	40000	80000	120100	160100
Auxiliary power, kW	1542	1542	1542	1542	1542
Gross heat rate, Btu/kWh (LHV)	38490	16900	12770	11150	10240
Exhaust flow, lb/h	$2432x10^3$	$2443x10^3$	$2501x10^3$	$2681x10^3$	$3365x10^3$
Exhaust Temp., °F	740	886	1084	1200	1133
Inlet guide vane position, degrees	54	54	54	58.3	88
Fuel flow, lb/h	26561	36442	55072	72189	88377
Water injection flow lb/h	0	0	38960	68390	93580
Nitrogen oxides, ppmvd at 15 percent O_2	55	84	42	42	42
Nitrogen oxides, lb/h as NO_2	104	228	175	231	286
Carbon monoxide, ppmvd	731	372	87	20	20
Carbon monoxide, lb/h	1649	835	193	47	59
Sulfur dioxide, ppmw	5	6	9	12	11
Sulfur dioxide, lb/h	25	35	52	69	84
TSP, lb/h (non-condensables only)	17	17	17	17	17
PM10, lb/h (non-condensables only)	17	17	17	17	17
TSP, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
PM10, lbm/h (excluding H_2SO_4, Including other condensables)	37	38	40	42	44
H_2SO_4, lbm/h	3	4	6	8	10

***** WITHOUT INLET BLEED HEATING *****

TABLE 1.5 - 6

Unburned hydrocarbon, ppmvw	119	42	11	7	7
Unburned hydrocarbon, lb/h	162	57	16	11	13
Volatile organic compounds, ppmvw	59.5	21	5.5	3.5	3.5
Volatile organic compounds, lb/h	81	28.5	8	5.5	6.5
Oxygen, vol %	16.93	15.55	12.8	10.91	10.97
Nitrogen, vol %	74.73	74.42	72.03	70.5	70.25
Carbon, vol %	2.14	3.02	4.45	5.46	5.37
Argon, vol %	.9	.89	.86	.83	.84
Water, vol %	5.3	6.12	9.86	12.3	12.57
Opacity, percent	20	20	20	20	20

***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	95.	95.	95.	95.	95.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	150,500.	112,800.	75,200.	37,600.	160,100.	120,100.	80,100.	40,000.
Heat Rate (LHV)	Btu/kWh	9,760.	10,690.	12,940.	18,180.	10,240.	11,170.	13,270.	18,180.
Heat Cons. (LHV) X 10^6	Btu/h	1,468.9	1,205.8	973.1	683.6	1,639.4	1,341.5	1,062.9	727.2
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	149,890.	112,190.	74,590.	36,990.	158,560.	118,560.	78,560.	38,460.
Heat Rate (LHV) Net	Btu/kWh	9,800.	10,750.	13,050.	18,480.	10,340.	11,320.	13,530.	18,910.
Exhaust Flow X 10^3	lb/h	3254.	2691.	2265.	2064.	3365.	2693.	2318.	2089.
Exhaust Temp.	Deg F.	1144.	1170.	1200.	1043.	1133.	1200.	1200.	1053.
Exhaust Heat (LHV) X 10^6	Btu/h	901.9	776.4	679.4	527.2	936.0	810.4	701.1	540.4
Water Flow	lb/h	0.	0.	0.	0.	93,590.	69,010.	46,070.	19,720.
EMISSIONS									
NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	58.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	89.	73.	58.	156.	286.	232.	182.	123.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	58.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	54.	44.	35.	156.	286.	232.	182.	123.
CO	ppmvd	15.	15.	15.	61.	20.	20.	36.	254.
CO	lb/h	43.	36.	30.	115.	59.	47.	74.	480.
UHC	ppmvw	7.	7.	7.	28.	7.	7.	7.	21.
UHC	lb/h	13.	11.	9.	33.	13.	11.	9.	25.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.
EXHAUST ANALYSIS	% VOL.								
Argon		0.87	0.86	0.86	0.87	0.84	0.84	0.85	0.86
Nitrogen		72.71	72.76	72.89	73.50	70.25	70.48	71.33	73.01
Oxygen		12.10	12.24	12.64	14.42	10.97	10.92	11.83	14.06
Carbon Dioxide		3.82	3.75	3.57	2.74	5.37	5.45	4.99	3.78
Water		10.51	10.39	10.04	8.47	12.57	12.31	11.01	8.29

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	173,200.	129,900.	86,600.	43,300.	182,000.	136,500.	91,000.	45,500.
Heat Rate (LHV)	Btu/kWh	9,370.	10,120.	12,190.	16,820.	10,010.	10,830.	12,780.	17,070.
Heat Cons. (LHV) X 10^6	Btu/h	1,622.9	1,314.6	1,055.7	728.3	1,821.8	1,478.3	1,163.	776.7
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	172,590.	129,290.	85,990.	42,690.	180,460.	134,960.	89,460.	43,960.
Heat Rate (LHV) Net	Btu/kWh	9,400.	10,170.	12,280.	17,060.	10,100.	10,950.	13,000.	17,670.
Exhaust Flow X 10^3	lb/h	3542.	2890.	2397.	2182.	3683.	2827.	2406.	2215.
Exhaust Temp.	Deg F.	1116.	1139.	1184.	1013.	1098.	1194.	1200.	1013.
Exhaust Heat (LHV) X 10^6	Btu/h	973.0	823.2	720.4	551.1	1011.7	865.3	744.8	562.1
Water Flow	lb/h	0.	0.	0.	0.	119,700.	90,620.	61,970.	27,170.

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	77.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	99.	79.	63.	220.	318.	256.	199.	131.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	77.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	60.	48.	38.	220.	318.	256.	199.	131.
CO	ppmvd	15.	15.	15.	65.	20.	20.	30.	254.
CO	lb/h	48.	39.	33.	131.	65.	50.	63.	514.
UHC	ppmvw	7.	7.	7.	30.	7.	7.	7.	23.
UHC	lb/h	14.	11.	9.	36.	15.	11.	9.	28.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.90	0.90	0.90	0.86	0.84	0.86	0.90
Nitrogen	74.39	74.44	74.55	75.23	71.30	71.26	72.20	74.38
Oxygen	12.38	12.51	12.85	14.80	11.09	10.69	11.62	14.35
Carbon Dioxide	3.90	3.84	3.69	2.78	5.48	5.75	5.28	3.83
Water	8.44	8.32	8.02	6.29	11.28	11.46	10.04	6.55

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	20.	20.	20.	20.	20.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	186,500.	139,900.	93,300.	46,600.	192,700.	144,500.	96,400.	48,200.
Heat Rate (LHV)	Btu/kWh	9,310.	9,950.	11,910.	16,280.	10,040.	10,840.	12,680.	16,690.
Heat Cons. (LHV) X 10^6	Btu/h	1,736.3	1,392.	1,111.2	758.6	1,934.7	1,566.4	1,222.4	804.5
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	185,890.	139,290.	92,690.	45,990.	191,160.	142,960.	94,860.	46,660.
Heat Rate (LHV) Net	Btu/kWh	9,340.	9,990.	11,990.	16,500.	10,120.	10,960.	12,890.	17,240.
Exhaust Flow X 10^3	lb/h	3801.	3025.	2486.	2297.	3914.	2925.	2439.	2332.
Exhaust Temp.	Deg F.	1081.	1112.	1160.	966.	1068.	1183.	1200.	962.
Exhaust Heat (LHV) X 10^6	Btu/h	1036.9	863.8	751.3	569.2	1074.8	913.4	777.8	578.7
Water Flow	lb/h	0.	0.	0.	0.	130,530.	100,950.	68,710.	28,730.

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	80.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	106.	84.	66.	238.	338.	271.	209.	136.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	80.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	64.	51.	40.	238.	338.	271.	209.	136.
CO	ppmvd	15.	15.	15.	104.	20.	20.	26.	282.
CO	lb/h	52.	41.	34.	221.	69.	51.	57.	605.
UHC	ppmvw	7.	7.	7.	47.	7.	7.	7.	27.
UHC	lb/h	15.	12.	10.	60.	15.	12.	10.	35.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.91	0.89	0.89	0.90	0.86	0.84	0.86	0.91
Nitrogen	74.99	75.00	75.11	75.86	71.77	71.48	72.40	74.99
Oxygen	12.54	12.57	12.88	15.00	11.20	10.54	11.39	14.59
Carbon Dioxide	3.90	3.89	3.75	2.77	5.49	5.89	5.48	3.78
Water	7.67	7.65	7.37	5.48	10.69	11.25	9.87	5.74

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat r correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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General Electric Company
(Bidder's Name)

1.5.4 General Data - Generator.

General Information

Number of main bearings, type, and design load	Two, Elliptical, 316 psi
Maximum allowable bearing temperature, °F	30 Degree F rise
Maximum allowable vibration for each bearing for continued operation, peak-to-peak, microns	3 mils pk-pk
Maximum allowable shaft deflection for continued operation, peak-to-peak, mils	N/A
Allowable frequency variation	
Limited time ±hertz/total time	-5 / +3 /10 Min.
Continually ±hertz/total time	+ / -2 /Continuous

Critical speeds	RPM	Mode
First critical	1015 / 1549	Lateral / Torsional
Second critical	2058 / 4314	Lateral / Torsional
Third critical	4337	Lateral
Fourth critical		

Miscellaneous Equipment	Manufacturer	Type
Annunciators	Later	Later
Prefabricated cables		
Pressure Transducers		
Pressure switches		
Control relays		
Control switches		
Push buttons		
Selector switches		
Indicating lights		

General Electric Company
(Bidder's Name)

Motor starters		
Light fixtures		
Convenience outlets		
Valves	Later	Later
Thermo Couple	Later	Later

Auxiliary Power

Guaranteed total electric load during normal operation for auxiliaries furnished with generator, ac load, kW	608/1542 Not Guaranteed
Total electric load during peak operation, ac load, kW	608/1542 Not Guaranteed
Emergency dc electric load, kW	125 Not Guaranteed

Generator Unit Weights and Dimensions

Weight of generator without excitation system and external accessories, lb tons	540,000 lbs.
Excitation system weight, lb tons	
Assembled weight of generator stator winding water cooling unit complete (dry/operating), lb tons (if required)	540,000 /
Weight of generator rotor, lb tons	76,000 lbs.

General Electric Company
(Bidder's Name)

List of major generator assemblies for shipment

Piece	Weight, tons

Voltage regulator and excitation system cubicles

Length, in.	See Mech. Outline
Depth, in.	See Mech. Outline
Height, in.	See Mech. Outline
Weight, lb	10,000

Overall dimensions, including enclosures

Length, ft	See Mech. Outline
Width, ft	See Mech. Outline
Height, ft	See Mech. Outline

Continuous rating at maximum H_2 pressure, rated power factor, and specified cooling water temperature, and based on maximum turbine rating as specified in the turbine specification, MVA	203.8 MVA
Nominal rpm	3600
Nominal frequency, hertz	60 Hz

General Electric Company
(Bidder's Name)

Voltages at continuous operation and nominal frequency

Nominal voltage, kV	18
Maximum voltage, kV	18.9
Minimum voltage, kV	17.1

Generator rated power factor (leading/lagging)	0.9 /0.95

Generator reactance in per unit value based on generator continuous kVA rating and nominal frequency	Estimated	Percent Tolerance Plus	Percent Tolerance Minus
Direct axis subtransient reactance (saturated at rated voltage) X"dv	0.144		

Short-time capability expressed in terms of $I_2{}^2t$	10
Short-circuit ratio at rated voltage and rated stator current	0.58
Continuous current unbalance expressed in terms of I_2, percent	8
Generator winding capacitance to ground, all phases tied together, mfd	1.086

Current transformers

Location	Refer to Electrical One Line	
Quantity		
Ratio		
Relaying accuracy		
Metering accuracy		
Thermal rating		
Mechanical rating		
Secondary resistance at 25° C		

	General Electric Company (Bidder's Name)	
Generator field voltage at maximum kVA output, volts	344	
Generator field current at maximum excitation, amperes	1644	
Generator moment of inertia, Newton-meter^2	83,898 lb/ft ^{2}	
Calculated value of H constant, combined moment of inertia of turbine and generator	0.855869 KVA/KW - SEC	
Maximum temperature rise above 40° C (104° F) gas temperature		
Generator armature winding temperature rise, °C	60°	
Generator field winding temperature rise, °C	70	
Generator core and mechanical parts adjacent to the insulation temperature rise, °C	65	
Maximum temperature rise above ambient air temperature if 40° C (104° F)		
Rotating armature winding temperature rise, °C	N/A	
Rotating field winding temperature rise, °C	N/A	
Collector rings temperature rise, °C	85	
Telephone influence factor (IEEE Standard 115)	Balanced	Residual
Calculated	8.46	
Guaranteed	40	
Wave form deviation factor (IEEE Standard 115)		
Calculated	Later	
Guaranteed	0.1	

General Electric Company
(Bidder's Name)

Temperature detectors located at	Number	Type
Armature	9	RTD
Rotating exciter	N/A	
Generator cold gas	4	RTD
Generator hot gas	2	RTD

Cooling System

Generator cooling system	Hydrogen
Stator core cooling	Hydrogen
Stator winding cooling	Hydrogen
Rotor winding cooling	Hydrogen
Rotating exciter cooling	N/A
Collector cooling	Air
Generator calculated losses at continuous nameplate MVA, voltage, and frequencY	
Total iron loss, kW	806.0
Generator stator I^2R loss, kW	213.7
Generator rotor I^2R loss, kW	565.9
Generator stray load loss, kW	Included
Generator windage loss, kW	247.6
Total generator loss excluding bearings and excitation system, kW	1845.5
Static exciter losses, kW	55.6
Excitation transformer losses, kW	Included in above
Generator efficiency, percent	98.97
Generator friction loss in bearings, seals, and collector rings, kW	251.3

General Electric Company
(Bidder's Name)

Generator Coolers

Number of coolers	5
Number of sections per cooler	One
Generator kVA capability with one cooler section out of service, percent	100%
Cooling water required by each generator cooler	
Inlet temperature, °F	95
Maximum flow, gpm	420 (total 2100 for all coolers)
Cleanliness factor	0.0005
Heat duty at maximum load, Btu/h	6,255,138 (1833.2 KW)
Tube side (water side) head loss through coolers	
Head, ft	18.2
Flow, gpm	2100
Tube side (water side) design conditions	
Pressure, psig	125
Temperature, °F	95
Complete for hydrogen-cooled generators	
CO_2 required to purge generator H_2 system, scf	7,264
H_2 required to fill system to maximum H_2 pressure after purging, scf	8,382 for 30 psig
Guaranteed H_2 consumption in 24 hours, scf	500 for 30 psig
H_2 seal oil flow, gpm	15
H_2 seal oil pressure, psig	35 psig

	General Electric Company (Bidder's Name)
Stator Winding Cooling Water System (if offered)	
Number of coolers	N/A
Generator kVA capability with one cooler section out of service, percent	N/A
Quantity of cooling water at design inlet water temperature, gpm	N/A
Tube side head loss through coolers	N/A ____ psi at ____ gpm
Tube side design conditions, psig/°F	N/A /
Heat duty at maximum load, Btu/h	N/A
Number of circulating pumps	N/A
Full- or half-capacity pumps	N/A
Stator cooling water demineralizer description	N/A
Excitation System	
Excitation system description	
Excitation system control system	
Make and type of excitation system	
Make and type of voltage regulator	
Communication method to operator interface	
Description of operator interface equipment	
Rated output of excitation system, kW	
Rated voltage, volts dc	

General Electric Company
(Bidder's Name)

Rated current, amperes dc	______
	______
Excitation system response ratio, p.u. minimum	______
Ceiling voltage, percent minimum	______
Does the excitation system meet the definition of high initial response as defined in IEEE Standard 421.1?	______Yes ______No

Rotating Exciter Cooling System
(if required)

Number of coolers	N/A
Generator kVA capability with one cooler out of service, percent	N/A
Heat duty at maximum load, Btu/h	N/A
Cooling water required by each exciter cooler, maximum gpm at 41° C	N/A
Tube side (water side) pressure drop through the coolers	N/A ______ psi at ____ gpm
Tube side design conditions, psig/°F	______ / ______

Motors	kW	Volts	Phase	Enclosure	Quantity
Hydrogen seal oil backup pump (dc)					
Hydrogen seal oil pump (ac)					
Hydrogen seal oil vacuum pump					
Stator winding cooling system pumps	N/A				
Other motors					
______					
______					
______					
______					

Subsection 1.1 - GENERAL DESCRIPTION AND SCOPE OF THE WORK

1.1.1 GENERAL. This Subsection covers the general description, scope of the work, and supplementary requirements for equipment, materials, and services included under these specifications.

The equipment and materials covered by these specifications will be incorporated in the Owner's Kennedy Generating Station and Brandy Branch Generating Station which will include a one and three complete 150-180 MW(nominal) Combustion Turbine generating units, respectively, operating in simple cycle mode.

The Kennedy Generating Station site is located at 4215 Talleyrand Avenue in Jacksonville, Florida. The Brandy Branch Generating Station site is located 2 miles northeast of Baldwin, Florida, in Duval County.

1.1.2 WORK INCLUDED UNDER THESE SPECIFICATIONS. The work under these specifications shall include furnishing f.o.b. at the Kennedy Generating Station site the combustion turbine generator unit with accessory equipment, and providing miscellaneous materials and services complete as specified herein.

All equipment and materials required for a complete combustion turbine generator shall be furnished, except as specified otherwise in these specifications. The equipment and materials to be furnished shall include, but not necessarily be limited to, the following major items:

Combustion turbine and accessories.

Hydrogen-cooled or air-cooled generator and accessories.

Electrical accessory equipment, including the following:

- Transformers - Excitation and startup isolation units only.
- 480 volt motor control centers.
- DC motor starters.
- Low voltage power and lighting systems.
- Surge protection for ac and dc panelboards.
- Batteries.
- Battery chargers/eliminators.
- Intrusion alarm switches.
- Raceway.
- Conductors.
- Grounding systems internal to furnished equipment.

Mechanical accessory equipment and materials, including the following:

- Lube oil cooling unit.
- Fuel oil forwarding system.
- Dry type low NO_x combustion system.

Water injection NO_x control system.

On-line and Off-line compressor wash system.

Fire detection and protection system.

Expanded unit enclosures/sound attenuation.

Multi-stage inlet air filtration system.

Inlet air duct and intake silencers.

Inlet bleed heating (external piping by others).

Exhaust system including exhaust duct, expansion joints, and stack.

Insulation and lagging.

Access provisions, including platforms, ladders and stairs.

Combustion turbine generator control system including the following:

Local control panels.

Remote control and monitoring equipment interface provisions. (Owner supplied equipment)

Sequence-of-events recorder.

Operating and maintenance training.

The equipment will be tested by the Owner after erection to demonstrate its ability to operate under the conditions and fulfill the guarantees as set forth herein. If the tests indicate that the equipment fails to meet guaranteed performance, the Contractor shall make additional tests and modifications in accordance with the requirements specified in Subsection 2.1.

The Contractor shall provide drawings and other engineering data, manufacturer's field services, tools, instruction manuals, recommended spare parts list, and miscellaneous materials and services, and shall participate in design conferences, all as specified herein.

Equipment, materials, and accessories furnished shall be delivered to the Kennedy Generating Station site where they will be received, unloaded, stored, and erected under separate contract. Deficiencies shall be sufficient cause to reject equipment f.o.b. carrier. Unloading from carrier and storing will not constitute acceptance.

1.1.3 MISCELLANEOUS MATERIALS AND SERVICES. Miscellaneous materials and services not otherwise specifically called for shall be furnished by the Contractor in accordance with the following:

All nuts, bolts, gaskets, special fasteners, backing rings, etc., between components and equipment furnished under these specifications.

All piping integral to skid mounted equipment furnished under these specifications, except as otherwise specified. This includes all vents, drains, instrument piping, insulation, lagging, pipe supports and other piping work required for a complete unit. Single piping connection points shall be provided for each service near grade level at the edge of the skids or equipment area. This includes fuel, air drains or any other piping systems.

Structural steel bolting materials between equipment furnished under these specifications.

Coupling guards for all exposed shafts and couplings.

Wiring and r.

Finish painti

Operating pe

1.1.5 CONTRACTO
be in accordance wit

1.1.5.1 Submittal of
to the design and sul
so that the Kennedy

The Contractor will b
herein to assure com

The Contractor shall
engineering schedul

1.1.5.2 Manufacture
representatives, on a
hauling, storing, clea

The Contractor shall
require field inspecti
any needed changes
equipment has been
done before initial op

The manufacturer's t
operating personnel

1.1.5.3 Design Con
Engineer or Owner t
additional design cor

1.1.5.4 Instruction M
these specifications

1.1.5.5 Recommend
with the Technical Pr
Combustion Turbine
portion of the Cost P

1. All spar

2. All spar
includir

3. All spa
inspect

4. All spa
path in

Leveling blocks, soleplates, thrust blocks, matching blocks, and shims.

Field office furnishings, supplies, telephone service, and equipment for the manufacturer's technical service representatives. Erection drawings, prints, information, instructions, and other data for use by the Owner's erection contractor.

Detailed storage requirements and lubrication requirements (including frequencies) for use by the Owner's erection contractor.

Turbine Maintenance Tools
- Guide pins (for removal or replacement of bearing caps, compressor casing and exhaust frame)
- Fuel nozzle wrenches
- Fuel nozzle test fixture
- Spark plug electrode tool
- Clearance tools
- Fuel nozzle staking tool
- Combustion liner tool
- Bearing and coupling disassembly fixture
- Turbine rotor lifting beam and guides (one for every four units)

Generator Maintenance Tools
- Rotor lifting slings
- Rotor removal equipment including shoes, pans, pulling devices
- Rotor jacking bolts

Erection Tools
- Trunnions for generator
    - On loan basis only
- Jacking bolts for generator
- Foundation/installation washer and shim packs

Erection tools shall remain the property of the Contractor and all shipping costs to and from the jobsite shall be at the Contractor's expense.

1.1.4 WORK NOT INCLUDED UNDER THESE SPECIFICATIONS. The following items of work will be furnished by the Owner:

Site preparation, grading and fencing.

Concrete embedded raceways.

Below grade grounding mat.

Receiving, unloading, storing, and field erection of all equipment.

Foundations, foundation bolts, bolt sleeves, and equipment bases.

Grouting materials and the placing thereof.

Cables (power and control) between skids and base mounted equipment.

Lubricants and fuels for operation.

Solvents and cleaning materials.

Piping and associated insulation and lagging between equipment skids and base mounted equipment.

aceway between equipment skids and base mounted equipment.

g of all equipment except as specified herein.

rsonnel for startup and tests.

R'S SERVICES. The services called for in WORK INCLUDED UNDER THESE SPECIFICATIONS shall n the following.

Engineering Data. Drawings and other engineering data for the specified equipment and materials are essential bsequent construction of the entire project. Time is a basic consideration in completing each phase of the work Generating Station Combustion Turbine can be in commercial operation on the specified date.

e required to submit drawings and engineering data in accordance with the schedule and requirements specified pliance with the overall construction and operating schedule.

allow a reasonable amount of time for mailing, processing, and Engineer's review of drawings and data in his and procurement/production/shipping schedule.

r's Field Services. The Contractor shall furnish the services of one or more manufacturer's field service resident basis, to provide technical direction to the Owner's erection contractor for unloading from transport, ning, installing, startup, and testing of the equipment furnished under these specifications.

also furnish the field services of direct representatives of the manufacturers of auxiliary equipment which may n and adjustment to assure proper operation. They shall inspect the equipment after its installation and make or adjustments to assure proper operation. They shall furnish written certification to the Owner that the inspected and adjusted by them or under their supervision and that it is ready for service, all of which shall be eration of the equipment.

echnical field representatives shall be present during the startup of the equipment and shall instruct the n its proper operation.

erence. The Contractor's design engineer shall attend a design conference at a time and place selected by the discuss matters relative to the execution of this Contract. The Contractor's design engineer shall attend ferences as required by the Engineer or Owner thereafter to expedite the work.

anuals. Instruction manuals shall be furnished in accordance with the requirements stated in Subsection 1.3 of and as scheduled herein.

ed Spare Parts. The Contractor shall provide the following recommended spare parts list and associated costs oposal. The spare parts shall include those required for all on-base and off-base equipment furnished with the The costs for all spare parts required as part of the Service Agreement shall be included in Service Agreement oposal. The recommended spare parts lists shall be submitted in separate lists as follows:

e parts and materials required through startup and testing.

e parts and materials that are expected to require replacement over the period of operation from startup to and g the first combustion inspection.

e parts and materials that are expected to require replacement over the period of operation from the combustion on to and including the hot gas path inspection.

e parts and materials that are expected to require replacement over the period of operation from the hot gas pection to and including the first major overhaul.

The listing shall include the manufacturer of each part, a description of each part (including industry standard part number if available), the assembly or equipment in which each part will be used, and recommended quantities to be stocked; shall classify the relative criticality of parts based on the manufacturer's experience; and shall list the lead time required for manufacture and deliveryof each part.

The Owner will retain the option of purchasing any one or any combination of spare parts listed at the prices quoted until 6 months after the date of commercial operation.

1.1.6 MILL AND FACTORY WITNESS TESTS. Supplementing the provisions of Subsection 2.1 concerning mill and factory witness tests, the Contractor shall notify the Engineer and Owner prior to the date of each mill or factory witness test as scheduled under Schedule of Activities.

1.1.7 SCHEDULE. The time of completion of the work is a basic consideration of the contract. This shall include the completion of various activities in accordance with the milestone time periods and dates listed in addition to the timely delivery of the equipment and materials.

The Schedule of Activities included at the end of this article stipulates the milestone time periods and dates for the work included in this Contract. It is necessary that the Contractor perform the activities shown on or before the dates indicated to avoid delay of the entire project.

1.1.7.1 Activity Periods and Dates. The time periods and dates listed in the Schedule of Activities indicate the latest dates by which the listed activities shall be completed. Data, drawings, and lists for planning, engineering, and documentation may be submitted earlier than the indicated dates at the Contractor's option.

Equipment and materials shall be delivered within the time frame specified. The Owner will not be obligated to accept delivery or make payment for equipment delivered prior to the earliest acceptable delivery date.

1.1.7.2 Engineering Schedule. The Contractor shall submit a schedule for engineering associated with the equipment being provided. Such schedules shall be updated and submitted by the first of each month until completion of the engineering effort.

1.1.7.3 Procurement/Production/Shipping Schedule. The Contractor shall submit a detailed procurement/ production/shipping schedule for the equipment and materials not later than the date indicated; thereafter, the schedule shall be updated as directed by the Engineer or Owner, but at least every 30 days.

1.1.7.4 Schedule of Activities.

Activity	Time of Submittal
Contractor to participate in design conference	15 days after contract award
Contractor's Schedules: Engineering Schedules	Preliminary with Technical Proposal, certified 30 days after contract award
Procurement/Production/ Shipping Schedules	Preliminary with Technical Proposal, certified 30 days after contract award
Drawings to Engineer and Owner	Drawing schedule according to Attachment 6 and Subsection 2.6.6, Logic Diagrams; Drawing submittal process according to Subsection 1.3-8, DRAWINGS.
Motor Information Sheets (motors < 4160 volts)	26 weeks after DFM
Motor Information Sheets (4160 volt motors)	12 weeks after DFM
Cost breakdown information	30 days after contract award

Cash flow projection	30 days after contract award
Review copy ("similar to") of Instruction Manual(s)	90 days prior to shipment of equipment
Twelve copies of Instruction Manuals	3 months after shipment of equipment
Hazardous materials documentation and list of materials	16 weeks after DFM
Recommended spare parts list to Owner	14 days after contract award
Notice of preshipment inspection	5 working days, as a minimum, prior to shipment
Notice of mill or factory witness tests or performance tests	10 working days prior to tests
Cut sheets and O&M data on specific components	3 months after shipment
Erection / Installaticn drawings	2 copies to JEA office - C. Bond

Activity	Dates			
Delivery	Unit 1	Unit 2	Unit 3	Unit 4
Contractor to deliver equipment to jobsite				
Begin delivery of major equipment (not before unless acceptable to JEA)	June 1, 1999	November 1, 1999	January 1, 2000	~~October 1, 2000~~ December 1, 2000
Complete delivery of all equipment and materials necessary for installation and operation of the Unit	October 31, 1999	April 1, 2000	June 1, 2000	~~February 28, 2001~~ Apri 30, 2001
Operation of Unit	Unit 1	Unit 2	Unit 3	Unit 4
Estimated Date of Initial Operation of Unit	April 1, 2000	November 15, 2000	November 15, 2000	~~October 1, 2001~~ December 1, 2001
Date of Commercial Operation of Unit	May 1, 2000	December 15, 2000	December 15, 2000	~~November 1, 2001~~ January 1, 2002

ATTACHMENT 1

TECHNICAL DATA SHEETS

General Electric Company
(Bidder's Name)

1.5.1 Performance Data - Combustion Turbine Generators.

Performance Data at Specified Conditions (Reference Table 2.1-1)

Parameter	Condition A	Condition B
Guaranteed or expected	Guaranteed	Guaranteed
Gross generator output, kW	173,200	182,000
CTG auxiliary power, kW	608	1542
CTG heat consumption, LHV, MBtu/h	1622.9	1821.8
Net CTG output, kW*	172.590	180,460
Net CTG heat rate, LHV, Btu/kWh*	9400	10,100
Fuel flow, lbm/h	78,746	98210
Water injection flow, lbm/h	0	119,700
Turbine inlet temperature °F	Proprietary	Proprietary
Inlet airflow, lbm/h	3,423,600	3,423,600
Inlet air pressure drop, in. H_2O	3.04	3.04
Compressor inlet temperature, °F	59	59
Exhaust pressure drop, in. H_2O	5.5	5.5
Exhaust gas flow, lbm/h	3542×10^3	3683×10^3
NO_x emissions at 15 percent O_2, ppmvd* (KGS: Kennedy Generating Station / BB: Brandy Branch)	15 (KGS) / 9 (BB)	42
NO_x emissions at 15 percent O_2, lbm/h*	99 (KGS) / 60 (BB)	318
CO emissions ppmvd*	15	20
CO emissions lbm/h*	48	65
UHC emissions, ppmvw*	7	7
UHC emissions, lbm/h*	14	15
VOC emissions, ppmvw*	1.4	3.5
VOC emissions, lbm/h*	2.8	7.5

General Electric Company
(Bidder's Name)

TSP, lbm/h*(non-condensables only)	9	17
PM10, lbm/h*(non-condensables only)	9	17
TSP, lbm/h*(excluding H_2SO_4, Including other condensables)	19	46
PM10, lbm/h*(excluding H_2SO_4, Including other condensables)	19	46
Opacity, percent*	5	20
SO_2, ppmvw, lbm/h*	0.0	93
H_2SO_4, lbm/h*		

Note: The basis for each load condition is specified in the Technical Requirements, Subsection 2.1, Performance Criteria. Items marked with an asterisk (*) shall be guaranteed for all load conditions designated "Guaranteed," in accordance with Subsection 2.1.

Auxiliary Power Requirements

	Included in Net Output, kW	Total Connected Power, kW
Turbine cooling air compressor	112	112
Control air compressor	---------------	--------------
Space heaters	20	90
Lube oil pumps (ac)	75	150
Lube oil pumps (dc)	-----------------	15
Lube oil cooler fans	120	120
Cooling water pumps	112	225
Generator cooling system	-------------------	-------------------
Rotor turning motor	-------------------	6
H_2 seal oil pump	8	8
Power oil pump	15	30
Vapor extractor	--------------------	-------------------
Mist eliminator	6	12
Control system	50	50
Air conditioners	50	100
Ventilation fans/blowers	40	70

	General Electric Company	
	(Bidder's Name)	
Other (ac) AA comp	373	746
Other (ac) Dnt. Fuel Htr		225
Other (ac) Fuel Feed Pump	38	76
Other Liquid Fuel Pump	300	300
Other ~~(dc)~~ Water Injection Pump	223	223
Total at continuous baseload	608 gas 1542 dist	
Total standby (turning gear operation) power	736	

Note: Auxiliary power data shall be for steady-state operation at the guaranteed load condition.

Startup and Shutdown Performance

Estimated ~~Guaranteed~~ normal cycle starting time from cold standby to synchronization and continuous baseload, min	~~Later~~13 minutes / 25 minutes
Estimated ~~Guaranteed~~ fast cycle starting time from cold standby to synchronization and continuous baseload, min.	~~Later~~13 minutes / 17 minutes
Estimated ~~Guaranteed~~ rate of load change, ~~kW~~%/min	~~Later~~ 8.33%/min (normal) / 25%/min (fast)
Total gross generation per start	
Normal start, kWh	Later
Fast start, kWh	Later
Total auxiliary power required per start	
Normal start, kWh	Later
Fast start, kWh	Later
Peak auxiliary power required per start, kW	Later
Fuel consumed per start (LHV)	
Normal start, Btu	Later
Fast start, Btu	Later

	General Electric Company
	(Bidder's Name)

Noise Emissions	Turbine	Generator
Guaranteed average near field noise levels at 3 feet from the combustion turbine generator and any associated auxiliary equipment, operating at full load, dBA to a reference of 20 micropascals	85	
Guaranteed far field noise levels at 400 feet from the combustion	dBA	dBC
turbine enclosure boundary, operating at full load	65	75

Reference band levels

Reference Only

Octave band center frequency, hertz	*Octave band levels* *Not guaranteed. For reference only.*
31	76
63	72
125	68
250	63
500	60
1,000	58
2,000	58
4,000	54
8,000	50

Operational Performance

Maintenance intervals

Combustion inspection	8000
Hot gas path	24,000
Major overhaul	48,000

	General Electric Company
	(Bidder's Name)

	Fired Hours of Operation				
Expected degradation data	1,000	4,000	8,000	16,000	24,000
Nonrecoverable degradation in baseload output, percent	See	Curve	In	Proposal	
Nonrecoverable degradation in baseload heat rate, percent	See	Curve	In	Proposal	

Miscellaneous

Bidder's definition of baseload	Unit Operating at Nominal Firing Temp
Bidder's definition of peak load	Not Applicable For This Equipment
Is a factory fired operation test completed for the unit proposed (Yes or No)	Yes
If yes, provide details	See Proposal

1.5.2 General Data - Combustion Turbine.

Manufacturer	GE	
Location assembled	Greenville, SC	
Combustion turbine model number	PG 7241 FA	
Gas delivery conditions		
Minimum required, psig, °F	400	
Maximum allowed, psig, °F	475	

General Design Information

Overspeed trip	
Electronic, rpm	3960
Mechanical bolt, rpm	N/A

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 21, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. N. Bert Gianazza, P.E.
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202-3139

Re: Second Request for Additional Information
DEP File No. 0310485-001-AC (PSD-FL-267)
Brandy Branch Facility - Three 170 MW Combustion Turbines

Dear Mr. Gianazza:

On June 22, 1999 the Department received your response to our letter of May 26 requesting additional information on the subject application. In order to continue processing your application, the Department will need the additional information 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. JEA's response to the request for "specific information on what costs are required in order to obtain a guarantee of 9 ppm" indicated that a guarantee of 9 ppm had been obtained. However, "JEA understands that this guarantee is valid only for the new and clean test performed after installation of the unit" and a GE letter dated December 8, 1998 was attached, noting that an improved guarantee of 9 ppm was available. The referenced letter did not incorporate details about the 9 ppm guarantee, only that one was available. The Department requests more explicit information about the 9 ppm guarantee, specifically including JEA's request for the guarantee and GE's response to the request. Additionally, please provide information relative to the cost of securing that guarantee.

2. In previous discussions, JEA has indicated that the Brandy Branch facility would be "replacing" older generating units with higher emissions. The South Side plant has been mentioned in those discussions. Please provide the Department with data reflecting the most recent 2 years worth of fuel consumed at that facility. The data should also include average annual pollutant emissions and hours of operation by fuel type for each generating unit. Additionally, please provide JEA's specific plans for the South Side facility in the event that the Brandy Branch facility is approved.

3. The Department has remaining questions concerning the request to "re-examine the use of fuel oil as a back-up fuel" and the corresponding effects on the Class I Significant Impact Levels for SO_2.

   a) Please provide cost information for procuring oil with a sulfur specification less than 0.05% for this project and estimate its impact on the Class I Significant Impact Levels for SO_2.

   b) As per previous correspondence with the Department, please rerun the Class I increment analysis including the Putnam County sources and all (eleven) Okefenokee receptors.

c) Please review and comment on the necessity of the Brandy Branch facility to be permitted to combust oil at the maximum hourly throughput for 24 hours each day on all three CT's (up to the requested limit of 800 hours per year).

We have received written comments from the Air Quality Branch of the Fish and Wildlife Service and are enclosing them, as they comprise a part of this completeness review.

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. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9530. Matters regarding review of the modeling should be directed to Chris Carlson (meteorologist) at 850/921-9537.

Sincerely,

7/21

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

AAL/mph

cc: Gregg Worley, EPA
Mr. John Bunyak, NPS
James L. Manning, P.E. RESD
Chris Kirts, DEP-NED
Anthony L. Compaan, P.E., Black & Veatch

Z 333 618 113

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

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Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 7-21-99 0310485-001-AC P50-F1-267	

PS Form **3800**, April 1995

Fold at line over top of envelope to

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
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I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
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3. Article Addressed to:
Mr. Bert Gianazza, P.E.
JEA
21 W. Church St.
Jacksonville, Fl
32202-3139

4a. Article Number
Z 333 618 113

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Technical Review of Additional Information
for Jacksonville Electric Authority's Brandy Branch Generating Station
Baldwin, Florida
by
Air Quality Branch, Fish and Wildlife Service – Denver
July 20, 1999

Jacksonville Electric Authority (JEA) is proposing to install three 170 MW simple cycle combustion turbines at their Brandy Branch Facility. The turbines will fire natural gas as the primary fuel, with low sulfur (less than 0.05 %) fuel oil as a back-up fuel. The Brandy Branch Facility is located 34 km southeast of Okefenokee Wilderness and 127 km southwest of Wolf Island Wilderness, both Class I air quality areas administered by the U.S. Fish and Wildlife Service (FWS). The project will result in PSD-significant increases in emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM), fine particulate matter less than 10 microns in diameter (PM-10), carbon monoxide (CO), and sulfuric acid mist (SAM). Proposed emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	858
SO_2	124
PM-10	75
CO	366
SAM	15.2

Air Quality Related Values (AQRV) Analysis

JEA performed a regional haze analysis for Wolf Island, concluding that the project would not contribute significantly to visibility impairment in the area. In December 1998, we advised JEA that they should also evaluate regional haze impacts in Okefenokee. Regional haze analyses are required of sources greater than 50 km from a receptor in a Class I area. Although the project was only 34 km from the nearest boundary of the Class I area, the project was more than 50 km from some receptors in the Class I area. (Okefenokee is approximately 55 km from south to north.)

An ISC analysis by JEA indicated that the project had the potential to significantly contribute to regional haze at Okefenokee. We advised the applicant that they had several options, including reducing production, accepting lower emissions limits, or performing a refined modeling analysis (CALPUFF-Lite or CALPUFF). In any case, they needed to demonstrate that the project's emissions would not significantly contribute to visibility impairment in the Class I area.

The applicant chose to do an analysis with CALPUFF-Lite (a screening version of CALPUFF) and submitted the results June 24, 1999. Although this model predicted impacts lower than impacts predicted with ISC, they were still significant. The change in visibility (light extinction) while burning gas was predicted to be 5.6%. The change in visibility (light extinction) while burning fuel oil was predicted to be 27.2%. FWS considers a change of greater than 5% to be significant and a potential adverse impact to the Class I area. At this time we reiterated JEA's options (see above). JEA stated its intention of doing a CALPUFF analysis, a refined version of CALPUFF-Lite.

On July 19, 1999, in a phone conversation with JEA, we learned that they had not yet started the CALPUFF analysis. However, JEA requested that the Florida Department of Environmental Protection issue an intent to permit the project on August 15. We advised JEA that, if they do not demonstrate by that time that the project's emissions would not significantly contribute to regional haze, we would object to the project. JEA agreed to start the CALPUFF analysis immediately. In addition, JEA agreed to accept as a permit condition the shut-down of their Southside Generating Station, 15 km south of Brandy Branch. JEA believes that the Southside shut-down would result in an emissions decrease that would more than offset new emission impacts from Brandy Branch. We stated our support of the shut-down, as it would result in a high-emitting facility being replaced by a more efficient and lower-emitting facility. We noted that such offsets should result in a net benefit to air quality at the Class I area, and that this should be demonstrated by modeling.

In summary, JEA needs to demonstrate to us that the proposed Brandy Branch project will not cause additional visibility impairment at Okefenokee Wilderness. JEA has a variety of options for doing this, including choosing not to proceed with the project, reducing the project's emissions, offsetting the project's emissions with the shut-down of Southside Station, and conducting a more refined modeling analysis. If refined modeling still predicts a significant contribution to visibility impairment from the project, FWS will consider the magnitude, duration, and frequency of impacts, and other factors in making an adverse impact determination.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Florida
Department of
Environmental Protection

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

Jeb Bush
Governor

David Struhs
Secretary

FAX TRANSMITTAL SHEET

DATE: 29 JUNE 1999

TO: Kyle Lucas

PHONE: 913-458-9062

FAX: 913-458-2934

FROM: Cleve Holladay

Division of Air Resources Management

PHONE: 29 JUNE 1999

FAX: **850.922.6979**

RE:

CC:

Total number of pages including cover sheet: 5

Message

Please insert these Putnam County SO_2 sources into the PSD Class I inventory and rerun 5 years of meteorology. If there are predicted exceedances of the inventory in the Okefenokee WA show that Brandy Branch does not significantly contribute ~~of~~ to any predicted exceedance.

If there are any problems with this fax transmittal, please call the above phone number.

HISTORICAL
SOUTHSIDE 4&5 {OIL UNITS}

CHUCK
JIM
SANDY
MARK
KYLE

OIL

6 MCF/HR
8MCF TOTAL {5MCF/HR BB + 3MCF/HR JAY
GAS - N. side

HISTORICAL OIL OPERATION

.05% .5%

40MCF/DAY

4000 GPS/YR 2001
3000 2002

2000 2005-

James 3:30 - 4:00 222-6853

Florida Pest

5 years of CALPUFF

apply at 50km

1 year of met data

Colorado Ammonia

PDF

No MORE ISC

Colorado Guidance

SAMSON CD Met Data

Mixing Height from SCRAM Bulletin Board

ISC Wet Deposition

52

PSD CLASS I INCREMENT

OTHER PUTNAM COUNTY SOURCES

APIS Number	Facility / Units	ISCST3 ID Name	Stack Parameters: Height (m)	Diameter (m)	Temper. (K)	Velocity (m/s)	Emission Rate (g/s)	(EXP/CON)
31JAX540025	Seminole Power Plant							
	Units 1 and 2	SEMELECT	205.7	10.97	326.5	7.99	2168.80	CON
31JAX540014	Florida Power & Light - Putnam							
	4x70Mw CT/HRSG + DB	FPLPUTNM	22.3	3.15	437.4	58.60	351.69	CON[a]
31JAX540016	Florida Power & Light - Palatka							
	Unit 2	FPLPALAT	45.7	3.96	408.1	9.50	-257.03	EXP

ISCST3 INPUT FILE


```
SO STARTING
** Source Location Cards:        G-P FUTURE
**        SRCID SRCTYP      XS          YS          ZS
SO LOCATION  TRS   POINT     434000.   3283400.      .0
SO LOCATION  RB4   POINT     434000.   3283400.      .0
SO LOCATION  SDT4  POINT     434000.   3283400.      .0
SO LOCATION  LK4   POINT     434000.   3283400.      .0
SO LOCATION  PB4   POINT     434000.   3283400.      .0
SO LOCATION  PB5   POINT     434000.   3283400.      .0
SO LOCATION  CB4   POINT     434000.   3283400.      .0
SO LOCATION  PB6   POINT     434000.   3283400.      .0


** G-P 1974 BASELINE
SO LOCATION  RB1B   POINT     434000.   3283400.      .0
SO LOCATION  RB2B   POINT     434000.   3283400.      .0
SO LOCATION  RB3B   POINT     434000.   3283400.      .0
SO LOCATION  RB4B   POINT     434000.   3283400.      .0
SO LOCATION  SDT1B  POINT     434000.   3283400.      .0
SO LOCATION  SDT2B  POINT     434000.   3283400.      .0
SO LOCATION  SDT3B  POINT     434000.   3283400.      .0
SO LOCATION  SDT4B  POINT     434000.   3283400.      .0
SO LOCATION  LK1B   POINT     434000.   3283400.      .0
SO LOCATION  LK2B   POINT     434000.   3283400.      .0
SO LOCATION  LK3B   POINT     434000.   3283400.      .0
SO LOCATION  LK4B   POINT     434000.   3283400.      .0
SO LOCATION  PB4B   POINT     434000.   3283400.      .0
SO LOCATION  PB5B   POINT     434000.   3283400.      .0
SO LOCATION  CB4B   POINT     434000.   3283400.      .0


** PUTNAM CO. SOURCES
SO LOCATION SEMELECT  POINT    438800    3289200     .0
SO LOCATION FPLPUTNM  POINT    443300.   3277600.    .0
SO LOCATION FPLPALAT  POINT    442800.   3277600.    .0


** Source Parameter Cards:
** POINT:  SRCID     QS      HS      TS      VS      DS

SO SRCPARAM  TRS     75.60   76.2   533.2   32.03   0.94
SO SRCPARAM  RB4     13.85   70.1   477.6   19.42   3.66
SO SRCPARAM  SDT4     1.00   62.8   344.3    6.46   1.52
SO SRCPARAM  LK4      1.37   39.9   338.7   18.53   1.35
SO SRCPARAM  PB4     45.23   61.0   474.8   21.82   1.22
SO SRCPARAM  PB5    197.13   70.7   502.6   18.47   2.74
SO SRCPARAM  CB4    145.03   72.2   499.8   21.88   2.44
SO SRCPARAM  PB6      1.40   18.3   622.0   17.43   1.83


** G-P 1974 BASELINE
SO SRCPARAM  RB1B    -6.21   76.2   360.0    8.80   3.66
SO SRCPARAM  RB2B    -8.88   76.2   372.0    8.80   3.66
SO SRCPARAM  RB3B    -8.58   40.5   372.0    7.28   3.41
SO SRCPARAM  RB4B   -34.97   70.1   474.0   16.86   3.66
SO SRCPARAM  SDT1B   -0.13   30.5   366.0    7.53   0.76
```

ISCST3 INPUT FILE


```
SO SRCPARAM  SDT2B    -0.18     30.5    375.0    9.51    0.91
SO SRCPARAM  SDT3B    -0.18     33.2    369.0    3.57    0.76
SO SRCPARAM  SDT4B    -0.71     62.8    346.0    8.26    1.52
SO SRCPARAM  LK1B     -0.24     15.2    401.0    5.24    1.28
SO SRCPARAM  LK2B     -0.24     15.9    341.0   10.67    1.71
SO SRCPARAM  LK3B     -0.48     15.9    342.0    8.47    1.71
SO SRCPARAM  LK4B     -1.40     45.4    351.0   16.46    1.31
SO SRCPARAM  PB4B    -45.22     37.2    477.0   14.54    1.22
SO SRCPARAM  PB5B   -161.15     72.9    520.0   15.97    2.74
SO SRCPARAM  CB4B   -121.28     72.9    477.0   10.52    3.05

** PUTNAM CO SOURCES
SO SRCPARAM SEMELECT  2168.8    205.7  326.5   7.99  10.97
** 2 OF FPL PUTNAM'S 4 CTS CONSUME PSD INCREMENT
SO SRCPARAM FPLPUTNM  175.85     22.3  437.4  58.60   3.15
SO SRCPARAM FPLPALAT -257.03     45.7  408.1   9.50   3.96
```

PSD CLASS I INCREMENT PAGE 1 of 2

Table 2-2. Maximum Baseline Emissions Used in the Modeling Analysis for Georgia-Pacific, Palatka

Emission Unit	Unit ID	SO_2 (1974) Short-Term Emissions (lb/hr)	(g/s)
No. 1 Recovery Boiler	RB1	49.3	6.21
No. 2 Recovery Boiler	RB2	70.5	8.88
No. 3 Recovery Boiler	RB3	68.1	8.58
No. 4 Recovery Boiler	RB4	277.5	34.97
No. 1 Smelt Dissolving Tank	SDT1	1.0	0.13
No. 2 Smelt Dissolving Tank	SDT2	1.4	0.18
No. 3 Smelt Dissolving Tank	SDT3	1.4	0.18
No. 4 Smelt Dissolving Tank	SDT4	5.6	0.71
No. 1 Lime Kiln	LK1	1.9	0.24
No. 2 Lime Kiln	LK2	1.9	0.24
No. 3 Lime Kiln	LK3	3.8	0.48
No. 4 Lime Kiln	LK4	11.1	1.40
No. 4 Power Boiler	PB4	358.9	45.22
No. 5 Power Boiler	PB5	1,279.0	161.15
No. 4 Combination Boiler	CB4	962.5	121.28
TOTALS		3,093.9	389.83

Table 2-1. Maximum Future Emissions Used in the Modeling Analysis for Georgia-Pacific, Palatka

Emission Unit	Unit ID	SO_2 (lb/hr)	(g/s
New Bleach Plant	BLCH	--	--
TRS Incinerator	TRS	600.0	75.60
No. 4 Recovery Boiler	RB4	109.9	13.85
No. 4 Smelt Dissolving Tank	SDT4	7.9	1.00
No. 4 Lime Kiln	LK4	10.9	1.37
No. 4 Power Boiler	PB4	359.0	45.23
No. 5 Power Boiler	PB5	1,564.5	197.13
No. 6 Power Boiler	PB6	11.1	1.40
No. 4 Combination Boiler	CB4	1,151.0	145.03
TOTALS		3,814.3	480.6

Table 1

ISCST3 Model Predicted Maximum Concentrations of SO_2 for the 24-Hour Period and Applicable Loads at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I SIL
One Turbine	24-Hour	100	1984	0.14	0.20
		75		0.12	0.20
		50		0.11	0.20
		100	1985	0.09	0.20
		75		0.08	0.20
		50		0.07	0.20
		100	1986	0.11	0.20
		75		0.10	0.20
		50		0.09	0.20
		100	1987	0.12	0.20
		75		0.11	0.20
		50		0.09	0.20
		100	1988	0.11	0.20
		75		0.12	0.20
		50		0.11	0.20
Two Turbines		100	1984	**0.28**	0.20
		75		**0.25**	0.20
		50		**0.21**	0.20
		100	1985	0.18	0.20
		75		0.16	0.20
		50		0.14	0.20
		100	1986	**0.22**	0.20
		75		**0.21**	0.20
		50		0.18	0.20
		100	1987	**0.24**	0.20
		75		**0.21**	0.20
		50		0.18	0.20
		100	1988	**0.22**	0.20
		75		**0.24**	0.20
		50		**0.22**	0.20
Three Turbines		100	1984	**0.42**	0.20
		75		**0.38**	0.20
		50		**0.32**	0.20
		100	1985	**0.28**	0.20
		75		**0.24**	0.20
		50		**0.21**	0.20
		100	1986	**0.33**	0.20
		75		**0.31**	0.20
		50		**0.28**	0.20
		100	1987	**0.36**	0.20
		75		**0.32**	0.20
		50		**0.27**	0.20
		100	1988	**0.34**	0.20
		75		**0.36**	0.20
		50		**0.32**	0.20

NOTE: Maximum Predicted Concentrations represent high first high impacts.

Table 2

ISCST3 Model Predicted Maximum Concentrations of SO_2 for the 24-Hour Period and Applicable Loads at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m³)	Class I SIL
One Turbine	24-Hour	100	1984	0.07	0.20
		75		0.07	0.20
		50		0.06	0.20
		100	1985	0.04	0.20
		75		0.04	0.20
		50		0.03	0.20
		100	1986	0.04	0.20
		75		0.03	0.20
		50		0.03	0.20
		100	1987	0.04	0.20
		75		0.04	0.20
		50		0.04	0.20
		100	1988	0.04	0.20
		75		0.03	0.20
		50		0.03	0.20
Two Turbines		100	1984	0.15	0.20
		75		0.13	0.20
		50		0.11	0.20
		100	1985	0.09	0.20
		75		0.08	0.20
		50		0.06	0.20
		100	1986	0.07	0.20
		75		0.06	0.20
		50		0.06	0.20
		100	1987	0.08	0.20
		75		0.07	0.20
		50		0.08	0.20
		100	1988	0.08	0.20
		75		0.07	0.20
		50		0.06	0.20
Three Turbines		100	1984	**0.22**	0.20
		75		**0.20**	0.20
		50		0.17	0.20
		100	1985	0.13	0.20
		75		0.11	0.20
		50		0.09	0.20
		100	1986	0.11	0.20
		75		0.10	0.20
		50		0.08	0.20
		100	1987	0.12	0.20
		75		0.11	0.20
		50		0.12	0.20
		100	1988	0.12	0.20
		75		0.10	0.20
		50		0.08	0.20

NOTE: Maximum Predicted Concentrations represent high first high impacts.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 23-Jun-1999 11:06am
From: Mike Halpin TAL
HALPIN_M
Dept: Air Resources Management
Tel No: 850/488-0114

To: Alvaro Linero TAL (LINERO_A)
CC: Teresa Heron TAL (HERON_T)

Subject: Re: Bert's memo on JEA Brandy Branch

Al -

Concerning Bert's memo below, I would make 3 points:

1) Bert states that GE will only guarantee 9 ppm after the initial test if they (GE) operate the units (which he says is not possible in JEA's case), and therefore JEA could not get a number for guaranteeing the 9 ppm into the future. CT maintenance and operation isn't a secret. It stands to reason that if GE CAN make a 9 ppm guarantee (if GE does the operation and maintenance), yet JEA CANNOT make that guarantee (if JEA does it), that either JEA does not have some measure of competency that GE does, or that JEA does not believe that GE can really do it. I find both possibilities to be poor enough to require a 9 ppm limit and let JEA figure it out; if they are unable to make it, they'll have to get GE in. I additionally do not find JEA's rationale for it being "impossible" to get GE to do their maintenance and operation as adequate reason to give JEA a higher NOx limit than other utilities. I think that what Bert is really saying is that he doesn't think that is a permit condition which he can take back to his superiors. I would want to understand JEA's rationale much better and would insist that JEA provide us with the "GE-9ppm" price (be it possible or not for JEA to consider) before I relinquished on that point.

2) Bert says that "In speaking with Mike, he is not comfortable giving us a complete on our application without completing the haze and visibility modeling." This is true. However, I would be willing to call it complete [pending our review of their recent responses, and with the caveat mentioned in 1) above] with Bert's understanding that the intent (to issue or deny) would not be issued until a satisfactory haze analysis is completed. Since time clocks get in our way, I'd rather not do this.

3) I can probably go with you to JEA one day next week, but prefer to wait until the following week.

I've left the previous e-mails below.

Mike

Bert's e-mail

Since GE will only guarantee the 9 ppm after the initial test if they operate the units (which is not possible in our case), we could not get a number for guaranteeing the 9 ppm in the future. The cost of obtaining the initial 9 ppm guarantee in lieu of the originally specified 15 ppm was $300,000 per unit ($900,000 total).

Our response to your RAI should be in your office for your consideration. I'd like to try to set up a meeting in the next week or two with system planning, engineering and ya'll (that's the southern plural of "you") to discuss the NOx limits, hours on oil, schedule, modeling, and whatever else. What is your availability next week, and would you be amenable to coming here?

Our construction schedule calls for start of construction on 10/1. In speaking with Mike, he is not comfortable giving us a complete on our application without completing the haze and visibility modeling. If we have to do CALPUF modeling, that could take 4-6 weeks, and would cause a serious schedule problem if we have to wait for the 90 day clock after that. We should have the CALPUF lite results today or tomorrow, and we will forward that info to Ellen Porter for review, per conversation with her. If we do have to do the CALPUF modeling, Ellen said she would not object to our application being deemed complete and doing the modeling concurrently with the application processing (we may need to put something in writing to that effect), but you would have to make that call. The other option would be to stand ready to issue the permit immediately after the modeling is finished and cut the 90 day clock short by about 4-6 weeks, if that is a viable approach.

I will keep you informed of developments. If you want to talk, just use my beeper number (904-818-6247).

I understand your and Ellen's position with regard to having to adequately address all the issues related to this project, and appreciate everything you're doing to try keep our schedule from slipping. I just hope we can find a way to do everything we need to do and still have a permit by 10/1.

Talk to you soon. Tx, Bert

From: Alvaro Linero TAL 850/921-9532[SMTP:Alvaro.Linero@dep.state.fl.us]
Sent: Wednesday, June 23, 1999 1:26 AM
To: giannb@jea.com
Cc: Mike Halpin TAL
Subject: JEA Brandy Branch
Sensitivity: Confidential

Hey Bert. I checked my phone messages and got your call. I forgot to update the message to show that I'm out. I'm at AWMA. I tried to track down Mark Barreta so we could meet with the Park service rep that was out here, but Mark left before I could collar him.

If the project is "permittable" I'm sure that it will get an Intent before the permit becomes the critical path.

I already wrote up TEC at Polk Power Station but it has not yet been issued for similar reasons. However, the production of the package is not a problem. Quite often the write-up takes a while. This one won't since we have good templates based on the JEA Kennedy write-up, the TEC project, and the Oleander draft.

Remember we were going to get a few details on the cost of the "continuing guarantee?" Any chances we could see that stuff?

I suggested to Mike that we meet with you soon one way or the other.

Thanks. Al Linero.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 23-Jun-1999 10:25am
From: Gianazza, N. Bert
GianNB@jea.com
Dept:
Tel No:

To: 'Alvaro Linero TAL 850/921-9532' (Alvaro.Linero@dep.state.fl.us)
CC: 'Mike Halpin' (Halpin_M@dep.state.fl.us)
CC: 'Bareta, Mark J.' (BaretaMJ@bv.com)

Subject: Re: JEA Brandy Branch

Since GE will only guarantee the 9 ppm after the initial test if they operate the units (which is not possible in our case), we could not get a number for guaranteeing the 9 ppm in the future. The cost of obtaining the initial 9 ppm guarantee in lieu of the originally specified 15 ppm was $300,000 per unit ($900,000 total).

Our response to your RAI should be in your office for your consideration. I'd like to try to set up a meeting in the next week or two with system planning, engineering and ya'll (that's the southern plural of "you") to discuss the NOx limits, hours on oil, schedule, modeling, and whatever else. What is your availability next week, and would you be amenable to coming here?

Our construction schedule calls for start of construction on 10/1. In speaking with Mike, he is not comfortable giving us a complete on our application without completing the haze and visibility modeling. If we have to do CALPUF modeling, that could take 4-6 weeks, and would cause a serious schedule problem if we have to wait for the 90 day clock after that. We should have the CALPUF lite results today or tomorrow, and we will forward that info to Ellen Porter for review, per conversation with her. If we do have to do the CALPUF modeling, Ellen said she would not object to our application being deemed complete and doing the modeling concurrently with the application processing (we may need to put something in writing to that effect), but you would have to make that call. The other option would be to stand ready to issue the permit immediately after the modeling is finished and cut the 90 day clock short by about 4-6 weeks, if that is a viable approach.

I will keep you informed of developments. If you want to talk, just use my beeper number (904-818-6247).

I understand your and Ellen's position with regard to having to adequately address all the issues related to this project, and appreciate everything you're doing to try keep our schedule from slipping. I just hope we can find a way to do everything we need to do and still have a permit by 10/1.

Talk to you soon. Tx, Bert

From: Alvaro Linero TAL 850/921-9532[SMTP:Alvaro.Linero@dep.state.fl.us]
Sent: Wednesday, June 23, 1999 1:26 AM
To: giannb@jea.com
Cc: Mike Halpin TAL
Subject: JEA Brandy Branch
Sensitivity: Confidential

Hey Bert. I checked my phone messages and got your call. I forgot to update the message to show that I'm out. I'm at AWMA. I tried to track down Mark Barreta so we could meet with the Park service rep that was out here, but Mark left before I could collar him.

If the project is "permittable" I'm sure that it will get an Intent before the permit becomes the critical path.

I already wrote up TEC at Polk Power Station but it has not yet been issued for similar reasons. However, the production of the package is not a problem. Quite often the write-up takes a while. This one won't since we have good templates based on the JEA Kennedy write-up, the TEC project, and the Oleander draft.

Remember we were going to get a few details on the cost of the "continuing guarantee?" Any chances we could see that stuff?

I suggested to Mike that we meet with you soon one way or the other.

Thanks. Al Linero.

INTEROFFICE MEMORANDUM

Date: 23-Jun-1999 09:01am
From: Mike Halpin TAL
HALPIN_M
Dept: Air Resources Management
Tel No: 850/488-0114

To: Alvaro Linero TAL (LINERO_A)
CC: Teresa Heron TAL (HERON_T)

Subject: Re: JEA Brandy Branch

Al -

We received JEA's sufficiency response yesterday, and I am reviewing it. Although they did not provide anything representing "the cost of continuing guarantee", we did not clearly request that in writing; our request stated "Please provide specific information on what costs are required in order to obtain a guarantee of 9 ppm as was provided for in that [Oleander] application." JEA did state that they estimated the cost to be $900,000 and that they have obtained that guarantee, HOWEVER they indicate that this is a new and clean guarantee only. They did not provide documentation from GE.

Al - I know that you want to get this thing out quickly, but if it was my call I would require JEA to meet 9 ppm on a continuous basis (as we did with Oleander) and give them 1000 hours of oil. I believe that we could structure the gas portion of their permit like Oleander's (i.e. - an annual stack test at 9 ppm and a 24 hour block average on a lb/hr basis) as well as the oil portion of their permit (an annual oil throughput limit with a 12 month rolling average compliance method). If JEA didn't like it, they could protest. If you wish to pursue this, let me know, as I believe you said that you were planning to take this permit over? If you wish to pursue this approach, let me take a crack at drafting the permit and we'll take it with us when we go to meet with Bert.

Let me know. Oh - We also have not received their regional haze analysis yet.

Mike

21 West Church Street
Jacksonville, Florida 32202-3139

RECEIVED
JUN 22 1999
BUREAU OF
AIR REGULATION

JEA

June 21, 1999

A. A. Linero, P.E. Administrator
New Source Review Section
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

PSD-FL-267
0310485-001-AC

Dear Mr. Linero:

In response to your letter of May 26, 1999 requesting additional information on the Jacksonville Electric Authority's Brandy Branch Facility air construction permit application for three 170 MW simple cycle combustion turbines, we are providing the following information.

1. **Request**: As indicated in the application, a recent BACT determination of General Electric simple cycle CTs for the Oleander Project resulted in NO_X emissions of 9 ppm. Please provide specific information on what costs are required in order to obtain a guarantee of 9 ppm as was provided for in that application.

   Response: The additional cost to obtain a 9 ppm guarantee for the Brandy Branch CTs was estimated at approximately $900,000. JEA has recently obtained this guarantee for these CTs. Please note that JEA understands that this guarantee is valid only for the "new and clean" test performed immediately after installation of the unit (see letter from GE dated December 8, 1998, attached). Long-term emissions are not guaranteed by GE. A copy of the Technical Data Sheets showing the original 15 ppm NO_X emission rate and the revised 9 ppm NO_X emission rate is provided as an attachment to this response.

2. **Request**: If costs were incurred to obtain a guarantee of 12 ppm from a higher level (e.g. 15 ppm), please provide that information.

   Response: A guarantee of 12 ppm has not been provided by GE. As mentioned in the response to question 1 above, the current guarantee by GE is for no more than 9 ppm of NO_X emissions during the "new and clean" test only. The 12 ppm value proposed by JEA is believed to represent BACT for these CTs based on actual performance data available from the Fort St. Vrain station, where a GE Frame 7FA with DLN 2.6 combustors is currently operating. Based on actual CEM data from this facility, JEA believes this level of NO_X emissions is achievable on a long-term basis.

Simple-cycle CTs such as these are typically used to provide electricity to the grid in response to varying (peaking) electrical load demand. These CTs are generally cycled from a cold (off) condition to a low load or a base load condition several times a day. They may also cycle from low load to base load during an operating day in response to the demand placed on the grid. Because combustion and burner conditions experience more variation in operating conditions, they experience a greater variation in resulting NOx emissions compared to base-load units. In simple-cycle (peaking) service, the number of "starts" determines the frequency of maintenance inspections, especially of the combustion section, rather than overall operating hours as with a base-load unit. This reflects the stress that multiple starts has on the combustion section and affects combustor performance, resulting in slightly increased NO_X emissions.

CEMs data recently submitted to the FDEP in support of JEA's Kennedy Generating Station air construction permit for a similar CT indicates that NO_X emissions were greater than 9 ppm approximately 27 % of the time. A closer examination of the data reveals that while the CT can typically provide NO_X emissions less than 9 ppm, occasional hourly NO_X emissions can exceed that value. JEA believes a BACT of 12 ppm of NO_X emissions provides a minimal margin to ensure long-term compliance with this limitation.

3. **Request**: Please explain why the "inlet bleed" data sheets show NO_X emissions on gas at 15 ppmvd.

   Response: These are the original data sheets for the project's proposed CTs. As mentioned above, GE has recently provided a 9 ppm guarantee for the "new and clean" test. This is for NO_X emissions only, and represents the only change from the original data. NO_X emissions were ratioed from the 15 ppm value to a 12 ppm value for the purpose of this permit application.

4. **Request**: Please provide the rationale for the 15 ppmvd at 15 % O_2 limit proposed for CO as BACT for natural gas firing. The combustors typically achieve 12 ppm of CO.

Response: BACT for the proposed CTs is good combustion control and the advanced combustor design. The 15 ppmvd of CO emission rate was provided by GE, and is the currently guaranteed value. While short-term, intermittent emissions of CO may be ("typically") less than 15 ppm, because of the type of firing-duty the combustor is expected to see during the proposed operation of the facility (simple-cycle peaking operation), JEA believes the guaranteed CO emission rate of 15 ppmvd appropriate for this facility.

5. **Request**: Please explain why 26.00 ppm CO while firing fuel oil is shown as the "Requested Allowable Emissions and Units" within each CTs Section H. Most other documentation indicates 20 ppm.

   Response: This is actually a typographical error and should read 36 ppm. This value is based on the maximum expected CO emission rate during operation at 50 % of load and at a 95 F ambient temperature. The 20 ppm CO emission rate is expected at all loads greater than 50 % of load, where the greater combustor efficiency results in reduced CO emissions. Note that the expected operation of the facility will result in minimal hours at reduced load, but this is a requested operating scenario.

6. **Request**: Please submit overlays (isopleths) of the maximum ground-level concentrations of NO_X, PM/PM_{10}, CO, and SO_2 with respect to the residential communities up to 2 miles (3.2 kilometers) from the proposed site.

   Response: All modeled impacts within 2 miles of the proposed site were less than the applicable significant impact levels. Based on these results, FDEP indicated the requested isopleths were not necessary (telephone conversation with Chris Carlson at FDEP).

7. **Request**: Please provide a detailed map showing the location of all of the sources and fence-line receptors used in the air quality impact analysis. These source and receptor locations should be shown in UTM coordinates since the UTM coordinate system is used in the modeling. In addition send us diskettes containing all of the air quality impact analysis modeling output files.

   Response: Enclosed with this response please find the requested maps and figures. Diskettes containing the requested modeling analysis were previously submitted to the FDEP.

8. **Request**: How will fuel oil be delivered to the site, e.g. pipeline or trucks? If by truck, please estimate the average number of fuel deliveries.

   Response: Fuel oil will be delivered to the site by truck. The average number of truck deliveries expected, at the maximum permitted annual fuel-oil firing rate, is approximately 11 trucks per day. The average number of truck deliveries expected, based on the "expected" annual fuel-oil firing rate, is less than 1 truck per day.

9. **Request**: Please re-examine the use of fuel oil as a back-up fuel. Provide an evaluation of 0, 1 and 2 CTs simultaneously combusting fuel oil and the corresponding effects on the Class I Significant Impact Levels for SO_2.

   Response: Fuel oil firing was evaluated in the original project design, and is envisioned as a back-up fuel source only. In the event of a natural gas curtailment or in an event where natural gas is not readily available as the primary fuel, fuel oil may be used to fire the CTs. This is primarily a backup fuel only, and this method of operation is limited by the requested number of hours of firing on this fuel. This amount of fuel oil firing was also evaluated as part of the air dispersion modeling analysis required under the Prevention of Significant Deterioration (PSD) program. Worst-case fuel-oil firing from the three CTs operating simultaneously were modeled and shown to have an impact greater than the significant impact level in both of the Class I areas for the short-term averaging periods. Additional cumulative interactive-source modeling of these and other significant sources of SO_2 was performed based on data provided by FDEP, and was shown to have a cumulative impact less than the applicable Class I allowable increment for SO_2 for each applicable period. This operating scenario therefore provides acceptable modeled impacts.

   Tables 5-5 through 5-8 of the permit application provide the maximum short-term modeled SO_2 impacts for the Okefenokee and Wolf Island wilderness areas. Based on the maximum modeled short-term (3-hr) impact resulting from operating of the proposed facility only, it appears that in order to avoid triggering the above mentioned cumulative source modeling, only a single turbine could be operating on fuel oil at any given time. This clearly would be an unacceptable operating scenario for the proposed facility. In the event natural gas is not readily available, it may be necessary to fire all three CTs on fuel oil in order to provide needed electricity.

10. **Request**: Provide the worst-case start-up and shutdown emission characteristics for the units under consideration including start-up curves and duration of excess emissions. The Department plans to address excess emissions in its BACT determination.

    Response: A revised Table showing estimated emissions for NO_X and CO at low loads is provided as an attachment to this response. It is expected that emissions during start-up and shutdown would follow these estimated performance curves. A copy of the start-up and shutdown procedures previously submitted to FDEP as part of the response to a request for additional information for JEA's Kennedy CT air construction permit is included as an attachment to this response.

If you have any further questions on this permit applications, please do not hesitate to contact me at (904) 665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Health & Safety Group

Enclosure[s]

cc: Mike Halpin, P.E., FDEP

CC: EPA
NPS
Duval Co.
NED

GE Energy Services

Marvin V. Sindel Jr.
Sales Manager

GE Energy Services Sales
General Electric International, Inc.
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Fx: 904-757-2652
Email: marvin.sindel@ps.ge.com

12/8/98

Subject: GE Frame 7FA Gas Turbine NOx Guarantee for JEA

Mr. Jim Connolly, P.E.
JEA
21 West Church Street
Jacksonville, FL. 32202

Dear Jim,

Pursuant to your question on the NOx emission guarantee for the GE Frame 7FA units that JEA has purchased, the following information is offered:

1. The GE guarantee for the units purchased is 15 ppm NOx. GE will guarantee this level only for the "new and clean" test performed immediately after the installation of the unit is complete. This guarantee is similar to GE guaranteeing the performance of the unit at the "new and clean" condition.

2. The unit will operate at the 15 ppm level only for load conditions above 50% load. Should JEA use the units in their peaking mode for load control and operate the unit below this load point, the NOx level will exceed the 15 ppm .

3. The current NOx guarantee is for 15 ppm. However, with some additional modifications, GE is able to offer an improved guarantee of 9 ppm NOx. GE is working on providing an optional price to JEA to change the contractual guarantee to 9 ppm NOx.

I hope this answers your questions concerning the GE units contractual guarantee concerning NOx emissions. Should you have any further questions regarding the GE units, please contact me at your convenience.

Respectfully,

Marv Sindel

Marvin Sindel
Sales Manager

cc: J. Grassman - GE Schenectady

***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	95.	95.	95.	95.	95.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	150,500.	112,800.	75,200.	37,600.	160,100.	120,100.	80,100.	40,000.
Heat Rate (LHV)	Btu/kWh	9,760.	10,690.	12,940.	18,180.	10,240.	11,170.	13,270.	18,180.
Heat Cons. (LHV) X 10^6	Btu/h	1,468.9	1,205.8	973.1	683.6	1,639.4	1,341.5	1,062.9	727.2
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	149,890.	112,190.	74,590.	36,990.	158,560.	118,560.	78,560.	38,460.
Heat Rate (LHV) Net	Btu/kWh	9,800.	10,750.	13,050.	18,480.	10,340.	11,320.	13,530.	18,910.
Exhaust Flow X 10^3	lb/h	3254.	2691.	2265.	2064.	3365.	2693.	2318.	2089.
Exhaust Temp.	Deg F.	1144.	1170.	1200.	1043.	1133.	1200.	1200.	1053.
Exhaust Heat (LHV) X 10^6	Btu/h	901.9	776.4	679.4	527.2	936.0	810.4	701.1	540.4
Water Flow	lb/h	0.	0.	0.	0.	93,590.	69,010.	46,070.	19,720.

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	58.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	89.	73.	58.	156.	286.	232.	182.	123.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	58.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	54.	44.	35.	156.	286.	232.	182.	123.
CO	ppmvd	15.	15.	15.	61.	20.	20.	36.	254.
CO	lb/h	43.	36.	30.	115.	59.	47.	74.	480.
UHC	ppmvw	7.	7.	7.	28.	7.	7.	7.	21.
UHC	lb/h	13.	11.	9.	33.	13.	11.	9.	25.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.86	0.86	0.87	0.84	0.84	0.85	0.86
Nitrogen	72.71	72.76	72.89	73.50	70.25	70.48	71.33	73.01
Oxygen	12.10	12.24	12.64	14.42	10.97	10.92	11.83	14.06
Carbon Dioxide	3.82	3.75	3.57	2.74	5.37	5.45	4.99	3.78
Water	10.51	10.39	10.04	8.47	12.57	12.31	11.01	8.29

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	173,200.	129,900.	86,600.	43,300.	182,000.	136,500.	91,000.	45,500.
Heat Rate (LHV)	Btu/kWh	9,370.	10,120.	12,190.	16,820.	10,010.	10,830.	12,780.	17,070.
Heat Cons. (LHV) X 10^6	Btu/h	1,622.9	1,314.6	1,055.7	728.3	1,821.8	1,478.3	1,163.	776.7
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	172,590.	129,290.	85,990.	42,690.	180,460.	134,960.	89,460.	43,960.
Heat Rate (LHV) Net	Btu/kWh	9,400.	10,170.	12,280.	17,060.	10,100.	10,950.	13,000.	17,670.
Exhaust Flow X 10^3	lb/h	3542.	2890.	2397.	2182.	3683.	2827.	2406.	2215.
Exhaust Temp.	Deg F.	1116.	1139.	1184.	1013.	1098.	1194.	1200.	1013.
Exhaust Heat (LHV) X 10^6	Btu/h	973.0	823.2	720.4	551.1	1011.7	865.3	744.8	562.1
Water Flow	lb/h	0.	0.	0.	0.	119,700.	90,620.	61,970.	27,170.

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	77.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	99.	79.	63.	220.	318.	256.	199.	131.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	77.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	60.	48.	38.	220.	318.	256.	199.	131.
CO	ppmvd	15.	15.	15.	65.	20.	20.	30.	254.
CO	lb/h	48.	39.	33.	131.	65.	50.	63.	514.
UHC	ppmvw	7.	7.	7.	30.	7.	7.	7.	23.
UHC	lb/h	14.	11.	9.	36.	15.	11.	9.	28.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.90	0.90	0.90	0.86	0.84	0.86	0.90
Nitrogen	74.39	74.44	74.55	75.23	71.30	71.26	72.20	74.38
Oxygen	12.38	12.51	12.85	14.80	11.09	10.69	11.62	14.35
Carbon Dioxide	3.90	3.84	3.69	2.78	5.48	5.75	5.28	3.83
Water	8.44	8.32	8.02	6.29	11.28	11.46	10.04	6.55

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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***** WITH INLET BLEED HEATING *****

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	20.	20.	20.	20.	20.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	186,500.	139,900.	93,300.	46,600.	192,700.	144,500.	96,400.	48,200.
Heat Rate (LHV)	Btu/kWh	9,310.	9,950.	11,910.	16,280.	10,040.	10,840.	12,680.	16,690.
Heat Cons. (LHV) X 10^6	Btu/h	1,736.3	1,392.	1,111.2	758.6	1,934.7	1,566.4	1,222.4	804.5
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	185,890.	139,290.	92,690.	45,990.	191,160.	142,960.	94,860.	46,660.
Heat Rate (LHV) Net	Btu/kWh	9,340.	9,990.	11,990.	16,500.	10,120.	10,960.	12,890.	17,240.
Exhaust Flow X 10^3	lb/h	3801.	3025.	2486.	2297.	3914.	2925.	2439.	2332.
Exhaust Temp.	Deg F.	1081.	1112.	1160.	966.	1068.	1183.	1200.	962.
Exhaust Heat (LHV) X 10^6	Btu/h	1036.9	863.8	751.3	569.2	1074.8	913.4	777.8	578.7
Water Flow	lb/h	0.	0.	0.	0.	130,530.	100,950.	68,710.	28,730.

EMISSIONS

NOx (KGS Unit)	ppmvd @ 15% O2	15.	15.	15.	80.	42.	42.	42.	42.
NOx AS NO2 (KGS Unit)	lb/h	106.	84.	66.	238.	338.	271.	209.	136.
NOx (BB Units)	ppmvd @ 15% O2	9.	9.	9.	80.	42.	42.	42.	42.
NOx AS NO2 (BB Units)	lb/h	64.	51.	40.	238.	338.	271.	209.	136.
CO	ppmvd	15.	15.	15.	104.	20.	20.	26.	282.
CO	lb/h	52.	41.	34.	221.	69.	51.	57.	605.
UHC	ppmvw	7.	7.	7.	47.	7.	7.	7.	27.
UHC	lb/h	15.	12.	10.	60.	15.	12.	10.	35.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

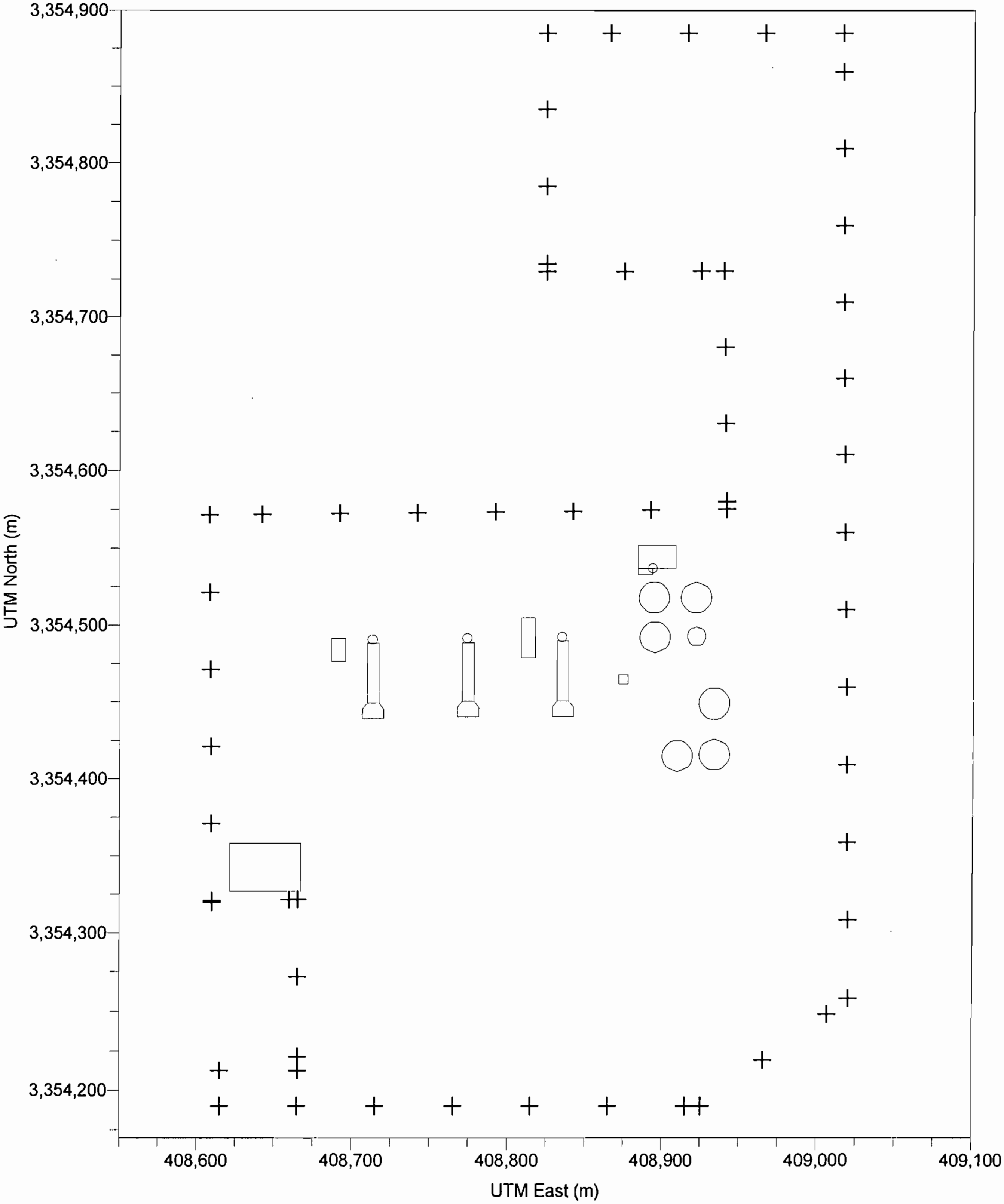
Argon	0.91	0.89	0.89	0.90	0.86	0.84	0.86	0.91
Nitrogen	74.99	75.00	75.11	75.86	71.77	71.48	72.40	74.99
Oxygen	12.54	12.57	12.88	15.00	11.20	10.54	11.39	14.59
Carbon Dioxide	3.90	3.89	3.75	2.77	5.49	5.89	5.48	3.78
Water	7.67	7.65	7.37	5.48	10.69	11.25	9.87	5.74

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

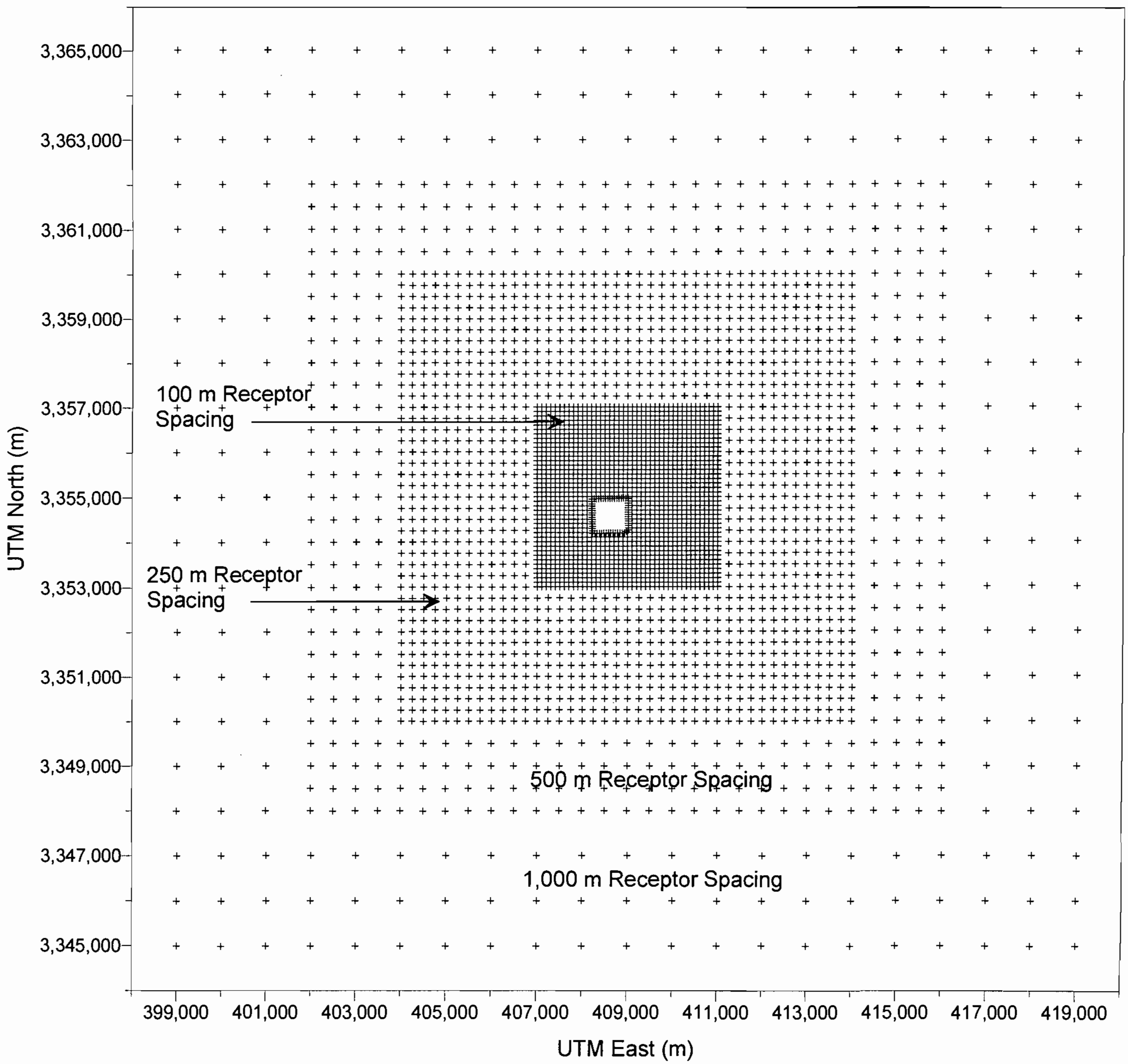
Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat ra correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

IPS- 70600 version code- 1 . 4 . 1 Opt: 10
ALMSTEJO 9/25/98 15:39 IBH 20F JEA.dat



Brandy Branch Facility Plot Plan

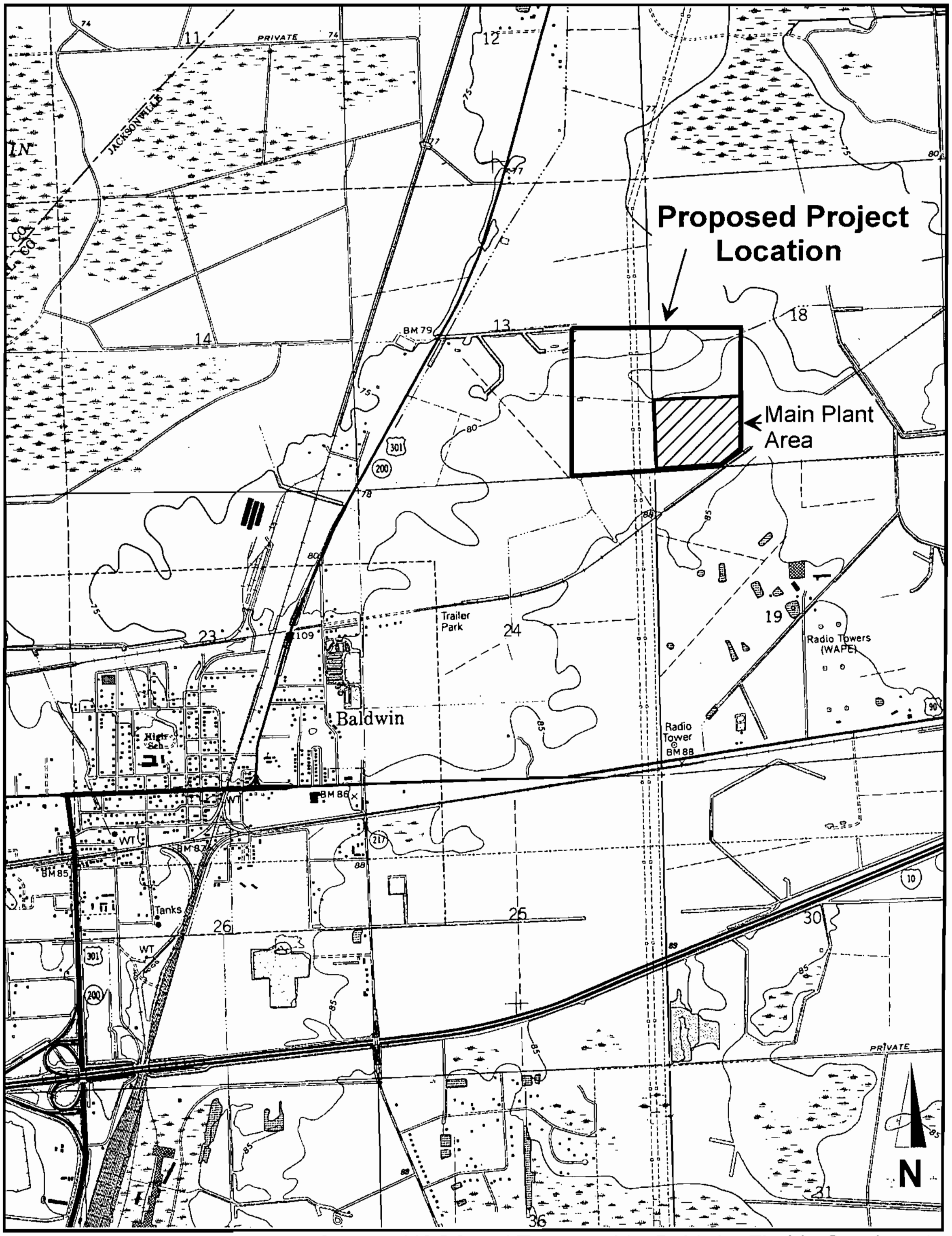
jeabldgs.srf



Receptor Locations

Figure 4-1

JEAGRID.SRF

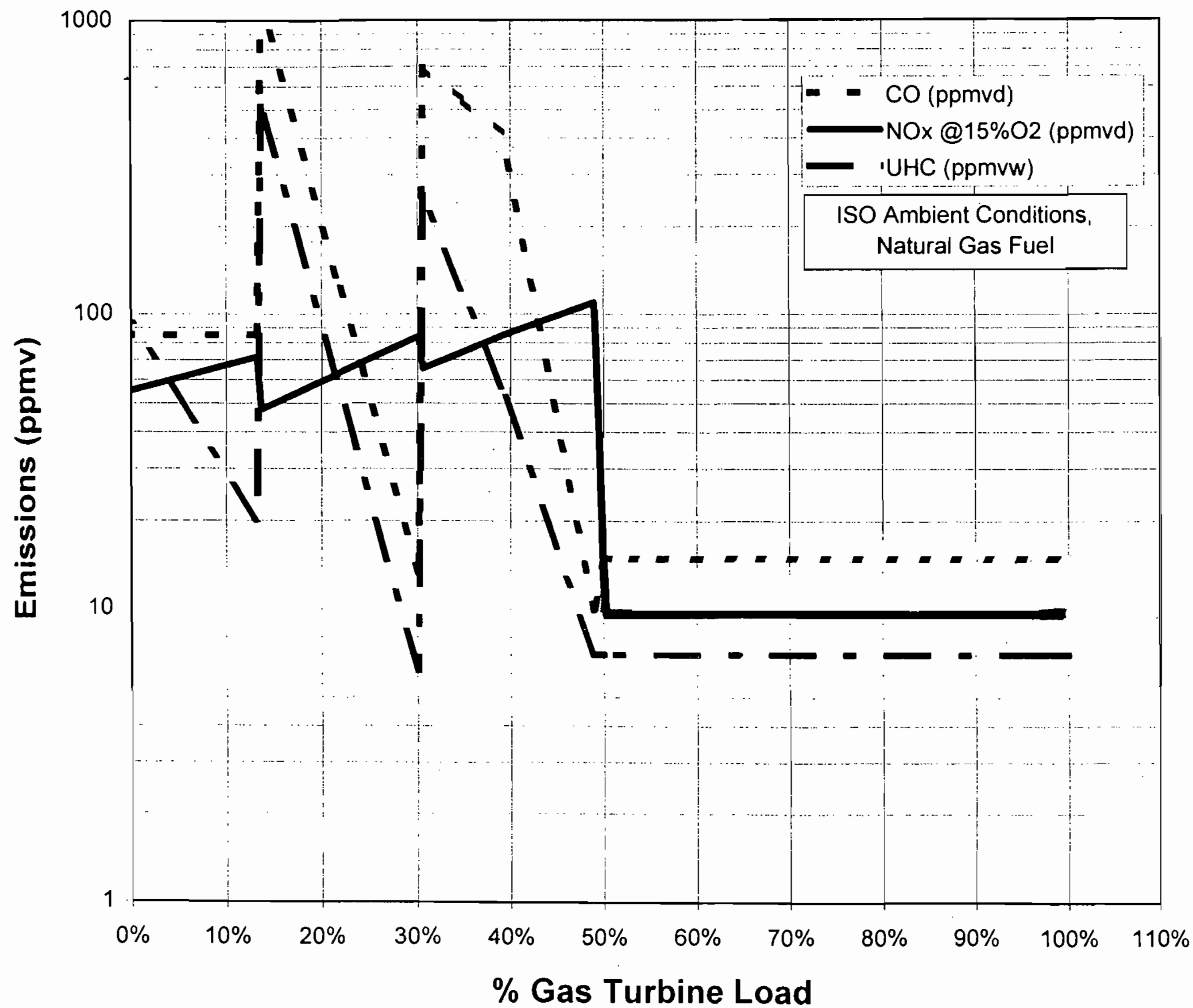


Source: USGS 7.5' Topographic, Baldwin, Florida Quadrangle

Proposed Project Location

Figure 2-1

PG7241FA with DLN2.6 Combustors
Estimated Emissions



GE Industrial & Power Systems
Gas Turbine

Unit Operation/Turbine (Gas)

(Applicability MS7001FA, 9001FA)

I. REFERENCE DATA AND PRECAUTIONS

A. Operator Responsibility

It is essential that the turbine operators be familiar with the information contained in the following operation text, the Control Specification drawings (consult the Control System Settings drawing for the index of Control Specification drawings), the Piping Schematic drawings including the Device Summary (consult the Control System Settings Drawing for the index by model list and drawing number of applicable schematics), the SPEEDTRONIC® control sequence program and the SPEEDTRONIC® Mark V Users' Manual (GEH–5979). The operator must also be aware of the power plant devices which are tied into the gas turbine mechanically and electrically and could affect normal operation. No starts should be attempted whether on a new turbine or a newly overhauled turbine until the following conditions have been met:

1. Requirements listed under CHECKS PRIOR TO OPERATION have been met.
2. Control systems have been functionally checked for proper operation before restarting.
3. All GENERAL OPERATING PRECAUTIONS have been noted.

It is extremely important that gas turbine operators establish proper operating practices. We emphasize adherence to the following:

1. Respond to Annunciator Indicators — Investigate and correct the cause of the abnormal condition. This is particularly true for the protection systems, such as low oil pressure, overtemperature, vibration, overspeed etc.
2. Check of Control Systems — After any type of control maintenance is completed, whether repair or replacement of parts, functionally check control systems for proper operation. This should be done prior to restart of the turbine. It should not be assumed that reassembly, "as taken apart" is adequate without the functional test.
3. Monitor Exhaust Temperature During All Phases of Startup — The operator is alerted to the following:

CAUTION

Overtemperature can damage the turbine hot gas path parts.

Monitor exhaust temperature for proper control upon first startup and after any turbine maintenance is performed. Trip the turbine if the exhaust temperature exceeds the normal trip level, or increases at an unusual rate. A particularly critical period for overtemperature damage to occur is during the startup phase before the turbine reaches governing speed. At this time air flow is low and the turbine is unable to accelerate away from excess fuel.

B. General Operating Precautions

1. Temperature Limits

Refer to the Control Specifications for actual exhaust temperature control settings. It is important to define a "baseline value" of exhaust temperature spread with which to compare future data. This baseline data is established during steady state operation after each of the following conditions:

a. Initial startup of unit

b. Before and after a planned shut-down

c. Before and after planned maintenance

An important point regarding the evaluation of exhaust temperature spreads is not necessarily the magnitude of the spread, but the change in spread over a period of time. The accurate recording and plotting of exhaust temperatures daily can indicate a developing problem. Consult Control Specification-Settings Drawings for maximum allowable temperature spreads and wheelspace temperature operating limits.

The wheelspace thermocouples, identified together with their nomenclature, are on the Device Summary. A bad thermocouple will cause a "High Wheelspace Differential Temperature" alarm. The faulty thermocouple should be replaced at the earliest convenience.

When the average temperature in any wheelspace is higher then the temperature limit set forth in the table, it is an indication of trouble. High wheelspace temperature may be caused by any of the following faults:

1. Restriction in cooling air lines
2. Wear of turbine seals
3. Excessive distortion of the turbine stator
4. Improper positioning of thermocouple
5. Malfunctioning combustion system
6. Leakage in external piping
7. Excessive distortion of exhaust inner diffuser

Check wheelspace temperatures very closely on initial startup. If consistently high, and a check of the external cooling air circuits reveals nothing, it is permissible to increase the size of the cooling air orifices slightly. Consult with a General Electric Company field representative to obtain recommendations as to the size that an orifice should be increased. After a turbine overhaul, all orifices should be changed back to their original size, assuming that all turbine clearances are returned to normal and all leakage paths are corrected.

CAUTION

> Wheelspace temperatures are read on the <I> CRT. Temperatures in excess of the maximum are potentially harmful to turbine hot-gas-path parts over a prolonged period of time. Excessive temperatures are annunciated but will not cause the turbine to trip. High wheelspace temperature readings must be reported to the General Electric technical representative as soon as possible.

2. Pressure Limits

Refer to the Device Summary for actual pressure switch settings. Lube oil pressure in the bearing feed header is a nominal value of 25 psig. The turbine will trip at 8 psig. Pressure variations between these values will result from entrapped particulate matter within the lube oil filtering system.

3. Vibration Limits

The maximum overall vibration velocity of the gas turbine should never exceed 1.0 inch (2.54 cm) per second in either the vertical or horizontal direction. Corrective action should be initiated when the vibration levels exceed 0.5 inch (1.27 cm) per second as indicated on the SPEEDTRONIC® <I> CRT.

If doubt exists regarding the accuracy of the reading or if more accurate and specific vibration readings are desired a vibration check is recommended using vibration test equipment.

4. Load Limit

The maximum load capability of the gas turbine is given in the control specification. For the upper limits of generator capability, refer to the Reactive Capability Curve following the GENERATOR AND ACCESSORIES tab.

5. Overloading of Gas Turbine, Facts Involved and Policy

It is General Electric practice to design gas turbines with margins of safety to meet the contract commitments and to secure long life and trouble-free operation.

So that maximum trouble-free operation can be secured, General Electric designs these machines with more than ample margins on turbine bucket thermal and dynamic stresses, compressor and turbine wheel stresses, generator ventilation, coolers, etc. As a result, these machines are designed somewhat better than is strictly necessary, because of the importance of reliability of these turbines to our customers and to the electrical industry.

It cannot be said, therefore, that these machines cannot be safely operated beyond the load limits. Such operation, however, always encroaches upon the design margins of the machines with a consequent reduction in reliability and increased maintenance. Accordingly, any malfunction that occurs as a result of operation beyond contract limits cannot be the responsibility of the General Electric Company.

The fact that a generator operates at temperature rises below the 185F (85C) for the rotor and 140F (60C) for the stator permitted by the AIEE Standards does not mean that it can be properly run with full safety up to these values by overloading beyond the nameplate rating. These standards were primarily set up for the protection of insulation from thermal deterioration on small machines. The imbedded temperature detectors of the stator register a lower temperature than the copper because of the temperature drop through the insulation from the copper to the outside of the insulation, where the temperature detectors are located. There are also conditions of conductor expansion, insulation stress, etc., which impose limitations. These factors have been anticipated in the "Vee" curves and reactive capability curves which indicate recommended values consistent with good operating practice. The "Vee" curves and reactive capability curves form part of the operating instructions for the generator and it is considered unwise to exceed the values given.

The gas turbines are mechanically designed so that (within prescribed limits), advantage can be taken of the increased capability over nameplate rating, which is available at lower ambient temperatures (because of increased air density), without exceeding the maximum allowable turbine inlet temperature.

The load limit of the gas turbine–generator must not be exceeded, even when the ambient temperature is lower than that at which the load limit of the gas turbine is reached. Under these conditions, the gas turbine will operate at this load with a lower turbine inlet temperature and the design stresses on the load coupling and turbine shaft will not be exceeded.

If the turbine is overloaded so that the turbine exhaust temperature schedule is not followed for reasons of malfunctioning or improper setting of the exhaust temperature control system, the maximum allowable turbine inlet temperature or the maximum allowable exhaust temperature, or both, will be exceeded and will result in a corresponding increase in maintenance and, in extreme cases, might result in failure of the turbine parts.

The exhaust temperature control system senses the turbine exhaust temperature and introduces proper bias to limit the fuel flow so that neither the maximum allowable turbine inlet temperature nor the maximum allowable turbine exhaust temperature is exceeded.

6. Fire Protection System Operating Precautions

The fire protection system, when actuated, will cause several functions to occur in addition to actuating the media discharge system. The turbine will trip, an audible alarm will sound, and the alarm message will be displayed on the <I> CRT. The ventilation openings in the compartments will be closed by a pressure-operated latch and the damper in the turbine shell cooling discharge will be actuated.

The annunciator audible alarm may be silenced by clicking on the alarm SILENCE target. The alarm message can be cleared from the ALARM list on the <I> CRT after the ACKNOWLEDGE target and the ALARM RESET target are actuated, but only after the situation causing the alarm has been corrected.

The fire protection system *must be replenished and reset* before it can automatically react to another fire. Reset must be made after each activation of the fire protection system which includes an initial discharge followed by an extended discharge period of the fire protection media.

Fire protection system reset is accomplished by resetting the pressure switch located on the fire protection system.

Ventilation dampers, automatically closed by a signal received from the fire protection system, must be reopened manually in all compartments before restarting the turbine.

CAUTION

> Failure to reopen compartment ventilation dampers will severely shorten the service life of major accessory equipment. Failure to reopen the load coupling compartment dampers will materially reduce the performance of the generator.

7. Combustion System Operating Precautions

WARNING

> **Sudden emission of black smoke may indicate a possibility of outer casing failure or other serious combustion problems. In such an event:**

a. Immediately shut down the turbine.

b. Allow no personnel inside the turbine compartment until turbine is shut down.

c. Caution all personnel against standing in front of access door openings into pressurized compartments.

d. Perform a complete combustion system inspection.

To reduce the possibility of combustion outer casing failure, the operator should adhere to the following:

a. During operation, exhaust temperatures are monitored by the SPEEDTRONIC® control system. The temperature spread is compared to allowable spreads with alarms and/or protective trips resulting if the allowable spread limits are exceeded.

b. After a trip from 75% load or above, observe the exhaust on startup for black or abnormal smoke and scan the exhaust thermocouples for unusually high spreads. Record temperature spread during a normal startup to obtain base line signature for comparison. Excessive tripping should be investigated and eliminated.

c. Adhere to recommended inspection intervals on combustion liners, transition pieces and fuel nozzles.

Operating a turbine with non-operational exhaust thermocouples increases the risk of turbine overfiring and prevents diagnosis of combustion problems by use of temperature differential readings.

To prevent the above described malfunctions the operator should keep the number of non-operational exhaust thermocouples to a maximum of two but no more than *one* of any three adjacent thermocouples.

CAUTION

> Operation of the gas turbine with a single faulty thermocouple should not be neglected, as even one faulty thermocouple will increase the risk of an invalid "combustion alarm" and/or "Trip". The unit should not be shut down just for replacement of a single faulty thermocouple. However, every effort should be made to replace the faulty thermocouples when the machine is down for any reason.

Adherence to the above criteria and early preventive maintenance should reduce distortions of the control and protection functions and the number of unnecessary turbine trips.

8. Cooldown/Shutdown Precautions

CAUTION

> In the event of an emergency shutdown in which internal damage of any rotating equipment is suspected, do not turn the rotor after shutdown. Maintain lube oil pump operation, since lack of circulating lube oil following a hot shutdown will result in rising bearing temperatures which can result in damaged bearing surfaces. If the malfunction that caused the shutdown can be quickly repaired, or if a check reveals no internal damage affecting the rotating parts, reinstate the cooldown cycle.

If there is an emergency shutdown and the turbine is not turned with the rotor turning device, the following factors should be noted:

a. Within 20 minutes, maximum, following turbine shutdown, the gas turbine may be started without cooldown rotation. Use the normal starting procedure.

b. Between 20 minutes and 48 hours after shutdown a restart should not be attempted unless the gas turbine rotor has been turned from one to two hours.

c. If the unit has been shut down and not turned at all, it must be shut down for approximately 48 hours before it can be restarted without danger of shaft bow.

CAUTION

> Where the gas turbine has not been on rotor turning operation after shutdown and a restart is attempted, as under conditions (1) and (2) above, the operator should maintain a constant check on vibration velocity as the unit is brought up to its rated speed. If the vibration velocity exceeds one inch per second at any speed, the unit should be shut down and the shaft rotated for at least one hour before a second starting attempt is made. If seizure occurs during the turning operation of the gas turbine, the turbine should be shut down and remain idle for at least 30 hours, or until the rotor is free. The turbine may be rotated at any time during the 30-hour period if it is free; however, audible checks should be made for rubs.

Note: The vibration velocity must be measured at points near the gas turbine bearing caps.

II. PREPARATIONS FOR NORMAL LOAD OPERATION

A. Standby Power Requirements

Standby AC power insures the immediate startup capability of particular turbine equipment and related control systems when the start signal is given. Functions identified by asterisk are also necessary for unit environmental protection and should not be turned off except for maintenance work on that particular function. Standby AC power is required for:

1. Lube oil heaters, which when used in conjunction with the lube oil pumps, heat and circulate turbine lube oil at low ambient temperatures to maintain proper oil viscosity.
2. *Control panel heating.
3. *Generator heating.
4. Lube oil pumps. Auxiliary pump should be run at periodic intervals to prevent rust formation in the lube oil system.
5. Fuel oil heaters, where used. These heaters used in conjunction with the fuel oil pumps, heat and circulate fuel oil at low ambient temperatures to maintain proper fuel oil viscosity.
6. Compartment heating.
7. *Operation of control compartment air conditioner during periods of high ambient temperature to maintain electrical equipment insulation within design temperature limits.
8. *Battery charging (where applicable).

B. Checks Prior to Operation

The following checks are to be made before attempting to operate a new turbine or an overhauled turbine. It is assumed that the turbine has been assembled correctly, is in alignment and that calibration of the

SPEEDTRONIC® system has been performed per the Control Specifications. A standby inspection of the turbine should be performed with the lube oil pump operating and emphasis on the following areas:

1. Check that all piping and turbine connections are securely fastened and that all blinds have been removed. Most tube fittings incorporate a stop collar which insures proper torquing of the fittings at initial fitting make up and at reassembly. These collars fit between the body of the fitting and the nut and contact in tightening of the fitting. The stop collar is similar to a washer and can be rotated freely on unassembled fittings. During initial assembly of a fitting with a stop collar, tighten the nut until it bottoms on the collar. The fitting has to be sufficiently tightened until the collar cannot be rotated by hand. This is the inspection for a proper fitting assembly. For each remake of the fitting, the nut should again be tightened until the collar cannot be rotated.
2. Inlet and exhaust plenums and associated ducting are clean and rid of all foreign objects. All access doors are secure.
3. Where fuel, air or lube oil filters have been replaced check that all covers are intact and tight.
4. Verify that the lube oil tank is within the operating level and if the tank has been drained that it has been refilled with the recommended quality and quantity of lube oil. If lube oil flushing has been conducted verify that all filters have been replaced and any blinds if used, removed.
5. Check operation of auxiliary and emergency equipment, such as lube oil pumps, water pumps, fuel forwarding pumps, etc. Check for obvious leakage, abnormal vibration (maximum 3 mils), noise or overheating.
6. Check lube oil piping for obvious leakage. Also using provided oil flow sights, check visually that oil is flowing from the bearing drains. The turbine should not be started unless flow is visible at each flow sight.
7. Check condition of all thermocouples and/or resistance temperature detectors (RTDs) on the <I> CRT. Reading should be approximately ambient temperature.
8. Check spark plugs for proper arcing.

WARNING

Do not test spark plugs where explosive atmosphere is present.

If the arc occurs anywhere other than directly across the gap at the tips of the electrodes, or if by blowing on the arc it can be moved from this point, the plug should be cleaned and the tip clearance adjusted. If necessary, the plug should be replaced. Verify the retracting piston for free operation.

9. Devices requiring manual lubrication are to be properly serviced.
10. Determine that the cooling water system has been properly flushed and filled with the recommended coolant. Any fine powdery rust, which might form in the piping during short time exposure to atmosphere, can be tolerated. If there is evidence of a scaly rust, the cooling system should be power flushed until all scale is removed. If it is necessary to use a chemical cleaner, most automobile cooling system cleaners are acceptable and will not damage the carbon and rubber parts of the pump mechanical seals or rubber parts in the piping.

Refer to "Cooling Water Recommendations for Combustion Gas Turbine Closed Cooling Systems" included under tab titled Fluid Specifications. Note the following regarding antifreeze.

CAUTION

> Do not change from one type antifreeze to another without first flushing the cooling system very thoroughly. Inhibitors used may not be compatible and can cause formation of gums, in addition to destroying effectiveness as an inhibitor. Consult the antifreeze vendor for specific recommendations.

Following the water system refill ensure that water system piping, primarily pumps and flexible couplings, do not leak. It is wise not to add any corrosion inhibitors until after the water system is found to be leak free.

11. The Load Commutator Inverter (LCI) should be calibrated and tested as per GEH–6192.
12. The use of radio transmitting equipment in the vicinity of open control panels is not recommended. Prohibiting such use will assure that no extraneous signals are introduced into the control system that might influence the normal operation of the equipment.
13. Check the Cooling and Sealing Air Piping against the assembly drawing and piping schematic, to ensure that all orifice plates are of designated size and in designated positions.
14. At this time all annunciated ground faults should be cleared. It is recommended that units not be operated when a ground fault is indicated. Immediate action should be taken to locate all grounds and correct the problems.

C. Checks During Start Up and Initial Operation

The following is a list of important checks to be made on a new or newly overhauled turbine with the OPERATION SELECTOR switch in various modes. The Control Specifications — Control Systems Adjustments should be reviewed prior to operating the turbine.

CAUTION

> Where an electric motor is used as the starting means refer to the Control Specifications for maximum operating time.

When a unit has been overhauled those parts or components that have been removed and taken apart for inspection/repair should be critically monitored during unit startup and operation. This inspection should include: leakage check, vibration, unusual noise, overheating, lubrication.

1. Crank

a. Listen for rubbing noises in the turbine compartment especially in the load tunnel area. A soundscope or some other listening type device is suggested. Shutdown and investigate if unusual noise occurs.

b. Check for unusual vibration.

c. Inspect for water system leakage.

2. Fire

*** WARNING ***

Due to the complexity of gas turbine fuel systems, it is imperative for everyone to exercise extreme caution in and near any turbine compartment, fuel handling system, or any other enclosures or areas containing fuel piping or fuel system components.

Do not enter the turbine compartment unless absolutely necessary. When it is necessary, exercise caution when opening and entering the compartment. Be aware of the possibility of fuel leaks, and be prepared to shut down the turbine and take action if a leak is discovered.

At any time, if/when entering the turbine compartment or when in the vicinity of the fuel handling system or other locations with fuel piping, fuel system components, or fuel system connections, while the turbine is operating, implement the following:

> **Conduct an environmental evaluation of the turbine compartment, fuel handling system, or specific area. Pay particular attention to all locations where fuel piping/components/connections exist.**
>
> **Follow applicable procedures for leak testing. If fuel leaks are discovered, exit the area quickly, shut the turbine down, and take appropriate actions to eliminate the leak(s).**
>
> **Require personnel entering the turbine comparrtment to be fitted with the appropriate personal protective equipment, i.e., hard hat, safety glasses, hearing protection, harness/manline (optional depending on space constraints), heat resistant/flame retardant coveralls and gloves.**
>
> **Establish an attendant to maintain visual contact with personnel inside the turbine compartment and radio communications with the control room operator.**

During the first start-up after a disassembly, visually check all connections for fuel leaks. Preferably check the fittings during the warm-up period when pressures are low. Visually inspect the fittings again at full speed, no load, and at full load. Do not attempt to correct leakage problems by tightening fittings and/or bolting while lines are fully pressurized. Note area in question and, depending on severity of leak, repair at next shutdown, or if required shut unit down immediately. Attempts to correct leakage problem on pressurized lines could lead to sudden and complete failure of component and resulting damage to equipment and personnel injury.

a. Bleed fuel oil filters, if appropriate. Then check entire fuel system and the area immediately around the fuel nozzle for leaks. In particular check for leaks at the following points:

Turbine Compartment

(1) Fuel piping/tubing to fuel nozzle

(2) Fuel check valves

(3) Atomizing air manifold and associated piping (when used)

(4) Gas manifold and associated piping (when used)

Accessory Module

(1) Flow divider (when used)

(2) Fuel and water pumps

(3) Filter covers and drains

CAUTION

> Elimination of fuel leakage in the turbine compartment is of extreme importance as a fire preventive measure.

b. Monitor FLAME status on the <I> processor to verify all flame detectors are correctly indicating flame.

c. Monitor the turbine control system readings on the <I> processor for unusual exhaust thermocouple temperature, wheelspace temperature, lube oil drain temperature, highest to lowest exhaust temperature spreads and "hot spots" i.e. combustion chamber(s) burning hotter than all the others.

d. Listen for unusual noises and rubbing.

e. Monitor for excessive vibration.

3. Automatic, Remote

On initial startup, permit the gas turbine to operate for a 30 to 60 minute period in a full speed, no load condition. This time period allows for uniform and stabilized heating of the parts and fluids. Tests and checks listed below are to supplement those recorded in Control Specification — Control System Adjustments. Record all data for future comparison and investigation.

a. Continue monitoring for unusual rubbing noises and shutdown immediately if noise persists.

b. Monitor lube oil tank, header and bearing drain temperatures continually during the heating period. Refer to the Schematic Piping Diagram — Summary Sheets for temperature guidelines. Adjust VTRs if required.

c. At this time a thorough vibration check is recommended, using vibration test equipment such as IRD equipment (IRD Mechanalysis, Inc.) or equivalent with filtered or unfiltered readings. It is suggested that horizontal, vertical and axial data be recorded for the:

(1) all accessible bearing covers on the turbine

(2) turbine forward compressor casing

(3) turbine support legs

(4) bearing covers on the load equipment

d. Check wheelspace, exhaust and control thermocouples for proper indication on the <I> CRT. Record these values for future reference.

e. Flame detector operation should be tested per the Control Specification — Control System Adjustments.

f. Utilize all planned shutdowns in testing the Electronic and Mechanical Overspeed Trip System per the Control Specifications — Control System Adjustments. Refer to Special Operations section of this text.

g. Monitor <I> CRT display data for proper operation.

III. OPERATING PROCEDURES

A. General

The following instructions pertain to the operation of a model series 7001FA or 9001FA gas turbine unit designed for generator drive application. These instructions are based on use of Mark V SPEEDTRONIC® turbine control panels.

Functional description of the <I> CRT Main Display follows; however, panel installation, calibration, and maintenance are not included.

Operational information includes startup and shutdown sequencing in the AUTO mode of operation. The most common causes of alarm messages can be found in the concluding section.

It is not intended to cover initial turbine operation herein; rather, it will be assumed that initial startup, calibration and checkouts have been completed. The turbine is in the cooldown or standby mode ready for normal operation with AC and DC power available for all pumps, motors, heaters, and controls and all annunciator drops are cleared.

Refer to the Control Specifications (Control and Protection Systems) in this volume, and the previously furnished Control Sequence Program (CSP) for additional operating sequence information and related diagrams.

B. Start-Up

1. General

Operation of a single turbine/generator unit may be accomplished either locally or remotely.

The following description lists operator, control system and machine actions or events in starting the gas turbine.

Reference the section "Description of Panels and Terms — Turbine Control Panel" for description of turbine panel devices. The following assumes that the unit is off of cooldown, and in a ready to start condition.

2. Starting Procedure

a. Using the cursor positioning device, select "MAIN" display from the DEMAND DISPLAY menu.

(1) The display will indicate speed, temperature, various conditions etc. Three lines displayed on the <I> CRT will read:

SHUTDOWN STATUS
OFF COOLDOWN
OFF

b. Select "AUTO" and "EXECUTE"

(1) The <I> CRT display will change to:

STARTUP STATUS
READY TO START
AUTO

c. Select "START" and "EXECUTE"

(1) Unit auxiliaries will be started including a motor driven lube oil pump used to establish lube oil pressure. The <I> CRT message SEQ IN PROGRESS will appear.

(2) When permissives are satisfied, the master protective logic (L4) will be satisfied. The CRT display will change to:

STARTUP STATUS
STARTING
AUTO;
START

(3) The turbine shaft will begin to rotate on turning gear. The zero speed signal "14HR" will be displayed. When the unit reaches approximately 6 rpm, the starting device will be energized and accelerate the unit. The <I> CRT display will change to START–UP STATUS/CRANKING.

(4) When the unit reaches approximately 15% speed, the minimum speed signal "14HM" will be displayed on the <I> CRT. (For machines with cooling water fan motors receiving power from the generator terminals via the UCAT transformer, field flashing will be initiated to build up generator voltage to power the fans; otherwise, field flashing to build up generator voltage will occur at operating speed.)

(5) If the unit configuration requires purging of the gas path prior to ignition, the starting device will crank the gas turbine at purge speed for a period of time determined by the setting of the purge timer. See Control Specifications-Settings Drawing for purge timer settings.

(6) FSR will be set to firing value. (FSR, Fuel Stroke Reference, is the electrical signal that determines the amount of fuel delivered to the turbine combustion system.) Ignition sequence is initiated. The <I> CRT display will change to START UP STATUS/FIRING.

(7) When flame is established, the <I> CRT display will indicate flame in those combustors equipped with flame detectors.

(8) FSR is set back to warm-up value, and the <I> CRT display will indicate STARTUP STATUS/WARMING UP. If the flame goes out during the 60 second firing period, FSR will be reset to firing value. (At the end of the ignition period, if flame has not been established, the unit will remain at firing speed. Refer to operation 8 in the Special Operations section for specific operating instructions for DLN 2.0 and DLN 2.6 configured machines.) At this time the operator may shut the unit down or attempt to fire again. To fire again select CRANK on the Main Display. The purge timer and firing timer are reinitialized. The purge timer will begin to time. Reselecting AUTO will cause the ignition sequence to repeat itself after the purge timer has timed out. If the unit is being operated remotely and multiple starts capability exists (REMOTE having previously been selected on the Main Display), and no fire has been established at the end of the ignition period, the unit will be purged of unburned fuel. At the end of the purge period ignition will be attempted again. If flame is not established at this time, the starting sequence will be terminated and the unit will shutdown.

At the end of the warmup period, with flame established, FSR will begin increasing. The <I> CRT will indicate STARTUP STATUS/ACCELERATING and the turbine will increase in speed. At approximately 50% speed, the accelerating speed signal "14HA" will be displayed on the <I> CRT.

(9) The turbine will continue to accelerate. When it reaches 85–90% speed, the starting device will disengage and shutdown. The <I> CRT will indicate the change in status from STARTUP CONTROL to SPEED CONTROL at approximately 60% speed.

(10) When the turbine reaches operating speed, the operating speed signal "14HS" will be displayed on the <I> CRT. Field flashing is terminated. If the synchronizing selector switch (43S) on the generator control panel is in the OFF position and REMOTE is not selected on the <I> CRT, as the turbine reaches operating speed, <I> CRT will now read:

RUN STATUS
FULL SPEED NO LOAD
AUTO; START

If the synchronizing selector switch on the generator panel is in the AUTO position or REMOTE is selected on the <I> CRT automatic synchronizing is initiated. The <I> CRT will read SYNCHRONIZING.

The turbine speed is matched to the system (to less than 1/3 Hz difference) and when the proper phase relationship is achieved the generator breaker will close. The machine will load to Spinning Reserve unless a load control point BASE, PEAK or PRESELECTED LOAD has been selected.

The <I> CRT will display SPINNING RESERVE, once the unit has reached this load point.

C. Synchronizing

When a gas turbine-driven synchronous generator is connected into a power transmission system, the phase angle of the generator going on-line must correspond to the phase angle of the existing line voltage at the moment of its introduction into the system. This is called synchronizing.

CAUTION

> Before initiating synchronization procedures, be sure that all synchronization equipment is functioning properly, and that the phase sequence of the incoming unit corresponds to the existing line phase sequence and the potential transformers are connected correctly to proper phases. Initial synchronization and checkout after performing maintenance to synchronizing equipment should be performed with the breaker racked out.

Note: **Synchronizing cannot take place unless AUTO or REMOTE has been selected on the <I> CRT Main Display and the turbine has reached full speed.**

Generator synchronization can be accomplished either automatically or manually. Manual synchronization is accomplished by the following procedure:

1. Place the synchronizing selector switch on the generator panel (43S) in the MANUAL position.
2. Select AUTO on the <I> CRT Main Display.
3. Select START and EXECUTE on the <I> CRT Main Display. This will start the turbine and accelerate it to full speed as previously described. At this point the CRT will indicate RUN STATUS, FULL SPEED NO LOAD.
4. Compare the generator voltage with the line voltage. (These voltmeters are located on the generator control panel.)
5. Make any necessary voltage adjustment by operating the RAISE- LOWER (90R4) switch on the generator panel until the generator voltage equals the line voltage.
6. Compare the generator and line frequency on the synchroscope (located on the generator control panel). If the pointer is rotating counterclockwise, the generator frequency is lower than the line frequency and should be raised by increasing the turbine-generator speed. The brightness of the synchronizing lights will change with the rotation of the synchroscope. When the lights are their dullest the synchroscope will be at the 12 o'clock position. The lights should not be used to synchronize but only to verify proper operation of the synchroscope.
7. Adjust the speed until the synchroscope rotates clockwise at approximately five seconds per revolution or slower.
8. The generator circuit breaker "close" signal should be given when it reaches a point approximately one minute before the 12 o'clock position. This allows for a time lag for the breaker contacts to close after receiving the close signal.

Automatic synchronization is accomplished by the following steps:

1. Place the synchronizing selector switch (43S) in the AUTO position.
2. Select AUTO on the <I> CRT Main Display.
3. Select START on the <I> CRT Main Display.

This procedure will start the turbine, and upon attainment of "complete sequence", match generator voltage to line voltage (if equipped with optional voltage matching), synchronize the generator to the line frequency, and load the generator to the preselected value. A "breaker closed" indicator will actuate when the generator circuit breaker has closed placing the synchronized unit on-line.

Once the generator has been connected to the power system, the turbine fuel flow may be increased to pick up load, and the generator excitation may be adjusted to obtain the desired KVAR value.

WARNING

Failure to synchronize properly may result in equipment damage and/or failure, or the creation of circumstances which could result in the automatic removal of generating capacity from the power system.

In those cases where out-of-phase breaker closures are not so serious as to cause immediate equipment failure or system disruption, cumulative damage may result to the on-coming generator. Repeated occurrences of out-of-phase breaker closures can eventually result in generator failure because of the stresses created at the time of closure.

Out-of-phase breaker closure of a magnitude sufficient to cause either immediate or cumulative equipment damage mentioned above will usually result in annunciator drops to notify the operator of the problem. The following alarms have been displayed at various occurrences of known generator breaker malclosures:

1. High vibration trip
2. Loss of excitation
3. Various AC undervoltage drops

Out-of-phase breaker closure will result in abnormal generator noise and vibration at the time of closure. If there is reason to suspect such breaker malclosure, the equipment should be immediately inspected to determine the cause of the malclosure and for any damage to the generator.

Refer to the "Control and Protection" section of this volume for additional information on the synchronizing system.

D. Normal Load Operation

1. Manual Loading

Manual loading is accomplished by clicking on the SPEED SP RAISE/SPEED SP LOWER targets on the <I> CRT Main Display.

Manual loading can also be accomplished by means of the governor control switch (70R4/CS) on the generator control panel. Holding the switch to the right will increase the load; holding it to the left will decrease the load.

Manual loading beyond the selected temperature control point BASE or PEAK is not possible. The manual loading rate is shown in the Control Specification-Settings Drawing.

Note: When manually loading with the governor control switch (70R4/CS) for load changes greater than 25% of full load, the operator should not change more than 25% of full load in one minute.

2. Automatic Loading

On startup if no load point is selected, the unit will load to the SPINNING RESERVE load point. The SPINNING RESERVE load point is slightly greater than no load, typically 8% of base rating.

An intermediate load point, PRE-SELECTED load, and temperature control load points BASE and PEAK can be selected anytime after a start signal has been given. The selection will be displayed on the <I> CRT. The unit will load to the selected load point. PRESELECTED LOAD is a load point greater than SPINNING RESERVE and less than BASE, typically 50%. The auto loading rate is shown in Control Specification-Settings Drawing.

E. Remote Operation

To transfer turbine control from the control compartment to remotely located equipment, select REMOTE on the <I> CRT Main Display. The turbine may then be started, automatically synchronized, and loaded by the remote equipment.

If manual synchronization is to be performed at the remote location, the synchronizing selector switch (43S) mounted on the generator control panel must be placed in the OFF/REMOTE position.

F. Shutdown and Cooldown

1. Normal Shutdown

Normal shutdown is initiated by selecting STOP on the <I> CRT Main Display. The shutdown procedure will follow automatically through generator unloading, turbine speed reduction, fuel shutoff at part speed and initiation of the cooldown sequence as the unit comes to rest.

2. Emergency Shutdown

Emergency shutdown is initiated by depressing the EMERGENCY STOP pushbutton. Cooldown operation after emergency shutdown is also automatic provided the permissives for this operation are met.

3. Cooldown

Immediately following a shutdown, after the turbine has been in the fired mode, the rotor is turned to provide uniform cooling. Uniform cooling of the turbine rotor prevents rotor bowing, resultant rubbing and imbalance, and related damage that might otherwise occur when subsequent starts are attempted without cooldown. The turbine can be started and loaded at any time during the cooldown cycle.

The cooldown cycle may be accelerated using the starting device; in which case it will be operated at cranking speed.

A rotor turning device is provided for cooldown rotation. A description of rotor turning operation and servicing can be found in the Starting System tab.

The minimum time required for turbine cooldown depends mainly on the turbine ambient temperature. Other factors, such as wind direction and velocity in outdoor installations and air drafts in indoor installations, can have an affect on the time required for cooldown. The cooldown times recommended in the following paragraphs are the result of General Electric Company operating experience in both factory and field testing of General Electric gas turbines. The purchaser may find that these times can be modified as experience is gained in operation of the gas turbine under his particular site conditions.

Cooldown times should not be accelerated by opening up the turbine compartment doors or the lagging panels since uneven cooling of the outer casings may result in excessive stress.

The unit must be on rotor turning operation immediately following a shutdown for at least 24 hours to ensure minimum protection against rubs and unbalance on a subsequent starting attempt. The General Electric Company, however, recommends that the rotor turning operation continue for 48 hours after shutdown to ensure uniform rotor cooling.

G. Special Operations

1. Fuel Transfer (Gas-Distillate Option)

Fuel transfer is initiated using the Fuel Mixture Display on the <I> CRT. When transferring from one fuel to the other, there is a thirty second delay before the transfer begins. For the gas-to-distillate transfer, the delay allows for filling the liquid fuel lines. For the distillate-to-gas transfer, the delay allows time for the speed ratio valve (and gas control valve) to modulate the inter volume gas pressure before the transfer begins. Once started, fuel transfer takes approximately thirty seconds. The transfer can be stopped at any fuel mixture proportion within limits as specified in the Control Specification-Settings Drawing by setting the FUEL MIX SETPOINT and then selecting MIX. Fuel transfer should be initiated prior to ignition or after the unit reaches operating speed.

2. Automatic Fuel Transfer On Low Gas Pressure (Gas-Distillate Option)

In the event of low fuel gas pressure the turbine will transfer to liquid fuel. The transfer will occur with no delay for line filling. To return to gas fuel operation after an automatic transfer, manually reselect gas fuel.

3. Testing the Emergency DC Lube Pump

The DC emergency pump may be tested using the test pushbutton on the motor starter.

4. **Overspeed Trip Checks**

Overspeed trip system testing should be performed on an annual basis on peaking and intermittently used gas turbines. On continuously operated units, the test should be performed at each scheduled shutdown and after each major overhaul. All units should be tested after an extended shutdown period of two or more months unless otherwise specified in the Control Specifications-Adjustments Drawing.

Note: The turbine should be operated for at least 30 minutes at rated speed before checking the overspeed settings.

Turbine speed is controlled by the turbine speed reference signal TNR. The maximum speed called for by TNR is limited by the high speed stop control constant. This value is nominally set at 107% of rated speed. It will be necessary to select the overspeed test function, which will reprogram the 107% setpoint to 113%, in order to allow the speed to increase above the electrical overspeed trip setting. With the high speed stop constant adjusted to be higher than the electrical overspeed trip speed, raise unit speed gradually by using the SPEED SP RAISE target on the <I> Main Display and observe speed at which the unit trips against the value tabulated in the Control Specifications — Setting drawing. Once the unit trips, the speed setpoint is returned to the 107% maximum value.

CAUTION

1. Do not exceed the maximum search speed as defined in the Control Specifications.
2. Return all constants to their normal value after coastdown of unit.

5. **Steam Injection Operation (Optional)**

Before operating the steam injection system for the first time following an overhaul or periods of extended shutdown, it is important that the following checks be made:

a. Steam supply is within design parameters

b. Instrument air supply is at required pressure

c. Steam line orifice size is correct

a. Pre-Operation Checks

Prior to operation, check for the following conditions:

a. <I> CRT controls are in non-select positions (Steam Injection OFF)

b. Manual stop valve is open

c. All hand valves in line of flow are open

d. All valves to temperature or pressure gauges are open

e. Steam supply pressure and temperature are in operating range

b. Startup

The automatic control system, in conjunction with logic circuits of the microcomputer of the SPEEDTRONIC® control system, operates the steam injection system control valving and assures that the proper amount of steam injection is provided to the turbine combustion system during operation.

To initiate steam injection the operator must first select the Steam Injection Overview Display on the <I> CRT. Selecting the STM INJ ON target initiates the steam injection control. At this point the automatic steam control circuits will take over, initiate the drain and stop valve sequences and control the system. When steam conditions are correct, the steam control valve releases steam into the combustion system at the proper steam-to-fuel flow ratio.

The startup and operating sequence of the steam injection system is described and explained in the Steam Injection control system text of the Control and Protection Tab.

c. Trouble Shooting

The purpose of the system is to provide steam to the turbine combustion system at the desired pressure, temperature and flow. If this does not happen, the following problems may be the cause:

(1) Steam supply exhausted

(2) Insufficient supply pressure

(3) Control valve closed

(4) Stop valve closed

The following should be checked:

(1) Adequate steam supply

(2) Check steam supply system

(3) Check control valve actuator and drain valve operation

(4) Check that instrument air supply pressure is sufficient and/or check solenoid control valve operation.

Alarm and shutdown conditions of the steam injection system are detected by a protection program built into Control Sequence Program. Alarm and trip indications are displayed on the <I> CRT. An alarm condition is initiated by high or low pressure levels and by high or low temperatures. See Control Specifications for alarm and trip point values.

The computer program is designed to trip the steam stop valve and prevent steam flow if steam temperature becomes too high or too low. It can trip the system on temperature or pressure to protect against loss of superheat and carry over of condensate. Steam at too high a pressure can cause damage to valve stem packing and system seals. A steam injection trip only shuts down the steam injection system. It does not trip the turbine.

6. DLNx II SYSTEM OPERATION

a. General

The Dry Low Nox II control system regulates the distribution of fuel delivered to multi–nozzle combustors located around the gas turbine. This system stages the fuel through multiple modes of operation to attain the low emissions mode of **Premix**. DLN–2 has only one burning zone but multiple nozzles and manifolds.

b. Gas Fuel Operation

There are three basic modes for fuel distribution to the combustor:

(1) Primary

Fuel to primary manifold only

(2) Lean–Lean

Fuel to primary and tertiary manifolds

(3) Premix

In this mode, fuel is in both the secondary and tertiary manifolds. This is the low emission mode.

c. Valves

There are four main valves in DLN–2:

Primary Gas Control Valve (GCVP)

Secondary Gas Control Valve (GCVS)

Quaternary Gas Control Valve (GCVQ)

Premix Splitter Valve (PMSV)

The PMSV is used downstream of the secondary gas control valve. This valve controls the flow between 4 secondary nozzles and 1 tertiary nozzle (The tertiary nozzle is not used during Primary mode).

d. Startup and Load Sequence

The gas turbine will startup with fuel going to primary manifold only and will accelerate to 81% corrected speed. At this point fuel flow will be initiated into the tertiary manifold and Lean–Lean will be established. As the unit is loaded to approximately 60% load (with no Bleed Heat), or 40% load (with Bleed Heat) a transfer to Premix will be performed. When transferring to Premix, the primary gas control valve will close, the secondary gas control valve will open,and the Premix splitter valve will modulate to control the flow between the tertiary and secondary nozzles. Once the Primary control valve is closed, the Primary Purge System wil open to purge the primary nozzles.

The sequence of events on an unload is as follows:

(1) Premix to Transfer Mode

(2) Premix Transfer to Lean–Lean

(3) Fired shutdown in Lean–Lean

The mode selection is performed automatically in the control system when the turbine is at the proper operating conditions.

These conditions must be met before startup; The following valves must be in the closed position:

Stop/Speed Ratio

Primary Control Valve (GCVP)

Secondary Control Valve (GCVS)

Quaternary Control Valve (GCVQ)

The Premix Splitter Valve (PMSV) should be at 100% split (no secondary flow).

Bleed Heat Valve closed (If applicable)

e. Inlet Guide Vane Operation (IGV)

The DLN–2 combustor emission performance is sensitive to changes in fuel to air ratio. The DLNx combustor was designed according to the airflow regulation scheme used with IGV Temperature Control. The IGV's should remain at a fixed minimum value from full speed no load until the turbine incrases load while on the exhaust temperature contro curve. The IGV's open from their minimum value as the turbine increases load while on the exhaust temperature control curve until they reach a maximum at Base Load.

IGV Temperature Control is defaulted to be "on", but the operator should always check this during startup. The only exception to this rule is when temperature matching is selected (see Temperature Matching below), or simple cycle IGV control is selected. Simple Cycle IGV control can be selected between breaker closer and 8 MW, or at Full open IGV's.

f. Inlet Heating

Operation of the gas turbine with reduced minimum IGV settings can be used to extend the Premix operating region to lower loads. Reducing the minimum IGV angle allows the combustor to operate near a constant firing temperature that is high enough to support Premix operation while maintaining a sufficient fuel to air ratio.

Inlet heating through the use of recirculated compressor discharge airflow is necessary when operating with reduced IGV angles in order to protect the turbine compressor. Inlet heating protects the turbine compressor from stall by relieving discharge pressure and by increasing the inlet air stream temperature. Also, inlet heating prevents ice formation due to increased pressure drop across the reduced IGV angle.

The inlet heating system regulates the compressor discharge bleed flow through a control vlave and into a manifold located in the compressor inlet air stream. The control valve varies the inlet air flow as a function of the IGV angle, compressor operating and ambient temperature.

g. Temperature Matching

Temperature matching is used when the gas turbine exhaust temperature is to be controlled to bring on a steam turbine. The operator must select temperature matching "on". Once selected, the turbine has to be loaded/unloaded to the matching window. Once the unit is in the matching window, the operator can enable matching with temperature matching on the Gas Turbine Exhaust temperature can be increased using the targets on the Temperature Matching Control Screen.

h. DLNx II Display Messages

The following display messages will appear on the control panel CRT in order to inform the operator of the current combustion mode of operation:

Primary Mode

Lean–Lean Mode

Secondary Prefill

Piloted Premix Mode

Premix Transfer Mode

Premix Steady State

Tertiary only FSNL Mode

7. Water Washing System Operation (Optional)

a. General

Water washing should be scheduled during a normal shutdown, if possible. This will allow enough time for the internal machine temperature to drop to the required levels for the washing. The time required to cool the machine can be shortened by maintaining the unit at crank speed. During this cooling of the turbine, the wash water is to be heated to the proper level.

b. Mandatory Precautions

Before water washing of the compressor begins, the turbine blading temperature must be low enough so that the water does not cause thermal shock.

CAUTION

> The differential temperature between the wash water and the interstage wheelspace temperature must not be greater than 120°F (48.9°C) to prevent thermal shock to the hot gas parts. For wash water of 180°F (82.2°C), the maximum wheelspace temperature must be no greater than 300°F (148.9°C) as measured by the digital thermocouple readout system on the turbine control panel.

To reduce this difference, the wash water may be heated and the turbine kept on crank until the wheelspace temperatures drop to an acceptable level. The wheelspace temperatures are read in the control room on the <I> CRT.

CAUTION

> If, during operation, there has been an increase in exhaust temperature spread above the normal 15°F to 30°F (8.3°C to 16.6°C), the thermocouples in the exhaust plenum should be examined. If they are coated with ash, the ash should be removed.Radiation shields should also be checked.
>
> If they are not radially oriented relative to the turbine, they should be repositioned per the appropriate drawing. If the thermocouples are coated with ash, or if the radiation shields are not properly oriented, a correct temperature reading will not be obtained.

If neither of the above conditions exists and there is no other explanation for the temperature spread, consult the General Electric Installation and Service Engineering representative.

WARNING

> **The water wash operation involves water under high pressure. Caution must be exercised to ensure the proper positioning of all valves during this operation. Since the water may also be hot, necessary precautions should be taken in handling valves, pipes, and potentially hot surfaces.**

Note: **Before water washing the compressor, inspect the inlet plenum and gas turbine bellmouth for large accumulations of atmospheric contaminants which could be washed into the compressor. These deposits can be removed by washing with a garden hose.**

c. Water Wash Procedures

Refer to cleaning publication included in this section for details on procedure.

8. Unit Operation After Failure to Fire on Liquid Fuel (DLN 2.0 or DLN 2.6)

The following only applies to units with DLN 2.0 or DLN 2.6 combustion systems. After every failure to fire on oil, a STOP command should be given and the unit allowed to decelerate to 2% speed and operate there for at least 2 minutes before being restarted on gas or liquid fuel. Currently, this must be done manually. This operation allows excess liquid fuel to drain from liners.

IV. DESCRIPTION OF PANELS AND TERMS

A. Turbine Control Panel (TCP)

The turbine control panel contains the hardware and software required to operate the turbine. A front elevation view of the panel can be seen in the Hardware Description.

EMERGENCY STOP (5E) — This red pushbutton is located on the front of the TCP. Operation of this pushbutton immediately shuts off turbine fuel.

BACKUP OPERATOR INTERFACE (BOI) — This interactive display is mounted on the front of the TCP. All operator commands can be issued from this module. In addition, alarm management can be performed and turbine parameters can be monitored from the <BOI>.

B. <I> CRT

The <I> CRT is a personal computer that directly interfaces to the turbine control panel. This is the primary operator station. All operator commands can be issued from the <I> CRT. Alarm management can be performed and turbine parameters can be monitored. With the proper password, editing can also be accomplished.

1. Main Display

Operator selector targets and master control selector targets can be actuated from the main display by using the cursor positioning device (CPD). Operator selector targets include:

OFF — Inhibits a start signal.

CRANK — With crank selected, a start signal will bring the machine to purge speed.

FIRE — With FIRE selected, a START signal will bring the machine to minimum speed and establish flame in the combustors. Selecting FIRE while the machine is on CRANK will initiate the firing sequence and establish flame in the combustors.

AUTO — With AUTO selected, a START signal will bring the machine to operating speed. Changing selections from FIRE to AUTO will allow the machine to accelerate to operating speed.

REMOTE — With REMOTE selected, control for the unit is transferred to the remote control equipment.

Master control selector targets include:

START — A START selection will cause the unit to start. With AUTO selected, the unit will load to the SPINNING RESERVE load point.

FAST START - A FAST START selection will cause the unit to start. With AUTO selected, the unit will load to the PRESELECTED load point. The machine will load at the manual loading rate.

STOP - A STOP selection will cause the unit to initiate a normal shutdown.

All operator selector switches and master control selector targets are green and are located on the right side of the display. All green targets are the AUTO/EXECUTE type, which means that the target must be selected with the CPD and then, within three seconds, the EXECUTE target at the bottom of the display must also be selected in order to actuate that command.

2. Load Control Display

Load selector targets can be actuated from the load control display by using the cursor positioning device (CPD). Load selector targets include:

PRESEL - Select the preselected load point.

BASE - Select base temperature control load point.

*PEAK - Select peak temperature control load point.

3. *Fuel Mixture Display

Fuel selector targets are used to select the desired fuel by using the cursor positioning device (CPD). Fuel selector targets include:

GAS SELECT - 100% gas fuel operation.

DIST SELECT - 100% distillate fuel operation.

MIX SELECT - Selecting MIX while on 100% single fuel will cause the machine to transfer to mixed fuel operation at a preset mixture (not applicable on DLN units).

4. *Isochronous Setpoint Display

Governor selector targets are used to select the desired type of speed control by using the cursor positioning device (CPD). Governor selector targets include:

DROOP SELECT - Used to select droop speed control.

ISOCH SELECT - Used to select isochronous speed control.

5. ***Inlet Guide Vane Control Display**

   The inlet guide vane (IGV) temperature control targets are IGV TEMP CNTL ON and IGV TEMP CNTL OFF. The IGV AUTO target selects normal operation of the IGVs. The IGV MANUAL target allows the maximum IGV angle to be manually set by the operator (not normally used while on–line).

6. **Alarm Display**

   This screen displays the current un–reset alarms, the time when each alarm occurred, the alarm drop number and a word description of the alarm. An "*" indicates that the alarm has not been acknowledged. The "*" disappears after the alarm has been acknowledged. For more information, see the Mark V Users' Manual (GEH–5979).

7. **Auxiliary Display**

   COOLDOWN ON and COOLDOWN OFF can be selected from this display.

8. **Manual Reset Target**

   Selecting the manual reset target resets the Master Reset Lockout function. This target must be selected so that the unit can be restarted following a trip.

C. Definition of Terms

SPINNING RESERVE - The minimum load control point based on generator output. The spinning reserve magnitude in MWs can be found in the control specifications (5–10% of rating is a typical value).

PRESELECTED LOAD - A load control point based on generator output. The preselected load point is adjustable within a range designated in the Control Specification. The preseelected load point is normally set below the base load point (50–60% of rating is a typical value).

BASE LOAD - This is the normal maximum loading for continuous turbine operation as determined by turbine exhaust temperature levels.

PEAK LOAD (Optional) - This is the maximum allowable output permitted for relatively long–duration, emergency power requirement situations consistent with acceptable turbine parts life. Peak loading duration is based on turbine exhaust temperature levels.

D. Generator Control Panel (Typical)

SYNCHRONIZING LAMPS — Rough indication of the speed and phase relationship between the generator and the bus.

FREQUENCY METER — Indicates generator frequency.

INCOMING VOLTMETER — Indicates generator voltage.

RUN VOLTMETER — Indicates bus voltage.

SYNCHROSCOPE — Indicates the phase relationship between the generator and bus voltage.

GENERATOR AMMETER — Indicates generator phase current. The phase current to be read is selected on the three position ammeter selector switch.

GENERATOR WATTMETER — Indicates the generator output in megawatts.

GENERATOR VARMETER — Indicates the generator reactive output in megavars.

GENERATOR TEMPERATURE METER — (Traditionally included on the Generator Control Panel, but actually displayed in Mark V SPEEDTRONIC® systems on the <I> CRT.) Reads the generator Resistance Temperature Detector (RTD) selected by the temperature meter selector switch.

EXCITER VOLTMETER — Indicates generator field voltage (if used).

GENERATOR FIELD AMMETER — Indicates generator field amperes (if used).

AMMETER SELECTOR SWITCH — See Generator Ammeter (above).

SYNCHRONIZING SELECTOR SWITCH (43S/CS) — Three position switch used to select the synchronizing mode.

Manual — Selects manual synchronizing mode. In this position the generator frequency and voltage, bus voltage, and phase relationship will be displayed to facilitate manual synchronizing.

Off/Remote — Used when the unit is being controlled from the remote control equipment.

Auto — Used for local automatic synchronizing.

VOLTMETER SWITCH (VS) — Used to select the phase of the bus voltage to be displayed on the run voltmeter.

TEMPERATURE METER SELECTOR SWITCH — Traditionally included on the Generator Control Panel, but actually displayed in Mark V SPEEDTRONIC® systems on the <I> CRT.

VOLTAGE/VAR CONTROL SWITCH (90R4/CS) — Controls generator voltage when the unit is off the line, and controls voltage/vars when the machine is on the line. (Increase — Right; Decrease — Left; spring return to normal.)

GENERATOR BREAKER CONTROL SWITCH (52G/CS) — Used to open or close the generator breaker. The indicator lights above the switch indicate Open (Green) and Closed (Red).

Note: Using this switch, the generator breaker should be closed only when proper synchronizing techniques are used or when the system onto which the generator is being brought is not energized.

GENERATOR DIFFERENTIAL LOCK-OUT SWITCH (86G) — Manual reset lockout switch which operates in the event of a generator fault.

GOVERNOR RAISE/LOWER CONTROL SWITCH (70R4/CS) — Used to control turbine speed when the generator is off the line (i.e. for manual synchronizing); generator load when the generator is on the line; and frequency when the generator is running isolated and on DROOP speed control.

TRANSFORMER DIFFERENTIAL LOCK-OUT SWITCH (86T) — Manual reset lockout switch which operates in the event of a transformer fault.

WATTHOUR METER — Measures the watthour output of the generator.

E. Motor Control Center

The turbine is provided with a motor control center for the control of the electrical auxiliaries. The motor control center includes AC and DC distribution systems.

Motor controllers are used for auxiliaries such as motors and heaters. Each motor controller normally consists of a breaker, control power transformer, control circuit, power contactor, selector switch and indicator lights. The selector switch is normally left in AUTO. Each motor control center is also provided with AC and DC distribution panel boards with circuit breakers.

F. Supervisory Remote Equipment

Supervisory equipment is normally functionally the same as the equipment described in the cable connected master panel. However, it may differ somewhat in metering and indications. Refer to the supervisory manufacturer's instruction manual for details.

G. Annunciator System

Alarms are displayed on the <I> CRT when the ALARM Display mode is selected. Before clearing an alarm, action should be taken to determine the cause and perform the necessary corrective action. The following is a list of annunciator messages along with suggested operator action.

Note: **The alarm messages can be categorized as either "trip" or "alarm". The "trip" messages contain the word TRIP in the message. The "alarm" messages do not indicate TRIP. For those alarms associated with permissive to start and trip logics latched up through the MASTER RESET function, it will be necessary to call up the <I> CRT Display with the Master Reset target in order to unlatch and clear these alarms.**

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INTEROFFICE MEMORANDUM

Date: 07-Jun-1999 09:32am
From: Mike Halpin TAL
HALPIN_M
Dept:
Tel No:

To: Alvaro Linero TAL (LINERO_A)

Subject: JEA - Brandy Branch

Al -

You may get a call from Bert with JEA. I had asked them a question (No. 9 of attached) which they apparently do not wish to answer. According to Chris Carlson who spoke with Bert last week, they said that they would "provide this additional information on the side, but do not wish to slow down the process". I would appreciate it if you would support me in the event JEA contacts you to get relief on this point.

Thanks
Mike

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 26, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. N. Bert Gianazza, P.E.
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202-3139

Re: Request for Additional Information
DEP File No. 0310485-001-AC (PSD-FL-267)
Brandy Branch Facility - Three 170 MW Combustion Turbines

Dear Mr. Gianazza:

On May 18, the Department received your application and complete fee for an air construction/operation permit for three 170-MW dual fuel, proposed 'F' class combustion turbines for the Brandy Branch Facility in Duval County. The application is incomplete. In order to continue processing your application, the Department will need the additional information 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. As indicated in the application, a recent BACT determination of General Electric simple cycle CT's for the Oleander Project resulted in NO_X emissions of 9 ppm. Please provide specific information on what costs are required in order to obtain a guarantee of 9 ppm as was provided for in that application.

2. If costs were incurred to obtain a guarantee of 12 ppm from a higher level (e.g. 15 ppm), please provide that information.

3. Please explain why the "inlet bleed" data sheets show NO_X emissions on gas at 15 ppmvd.

4. Please provide the rationale for the 15 ppmvd @ 15% O_2 limit proposed for CO as BACT for natural gas firing. The combustors typically achieve 12 ppm of CO.

5. Please explain why 26.00 ppm CO while firing oil is shown as the "Requested Allowable Emissions and Units" within each CT's Section H. Most other documentation indicates 20 ppm.

6. Please submit overlays (isopleths) of the maximum ground-level concentrations of NO_X, PM/PM_{10}, CO, and SO_2 with respect to residential communities up to 2 miles (3.2 kilometers) from the proposed site.

7. Please provide a detailed map showing the location of all of the sources and fence-line receptors used in the air quality impact analysis. These source and receptor locations should be shown in UTM coordinates since the UTM coordinate system is used in the modeling. In addition send us diskettes containing all of the air quality impact analysis modeling output files.

8. How will fuel oil be delivered to the site, e.g. pipeline or trucks? If by truck, please estimate the average number of daily deliveries.

9. Please re-examine the use of fuel oil as a back-up fuel. Provide an evaluation of 0, 1 and 2 CT's simultaneously combusting fuel oil and the corresponding effects on the Class I Significant Impact Levels for SO_2.

10. Provide the worst case start-up and shutdown emissions characteristics for the units under consideration including start-up curves and duration of excess emissions. The Department plans to address excess emissions in its BACT determination.

We are awaiting comments from the EPA and the National Park Service. We will forward them to you when received and they will comprise part of this completeness review.

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. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9530. Matters regarding review of the modeling should be directed to Chris Carlson (meteorologist) at 850/921-9537.

Sincerely,

AA Linero 5/26

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

AAL/mph

cc: Gregg Worley, EPA
Mr. John Bunyak, NPS
James L. Manning, P.E. RESD
Chris Kirts, DEP-NED
Anthony L. Compaan, P.E., Black & Veatch

Z 333 618 154

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PS Form **3800**, April 1995

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SENDER:
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- Complete items 3, 4a, and 4b.
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JEA
21 W. Church St.
Jacksonville, Fl
32202-3139

4a. Article Number
Z 333 618 154

4b. Service Type
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☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
5-28-99

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X D. Ghe

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PS Form **3811**, December 1994 102595-97-B-0179 **Domestic Return Receipt**

BLACK & VEATCH

8400 Ward Parkway, P.O. Box 8405, Kansas City, Missouri 64114, (913) 458-2000

JEA
Brandy Branch Project
Letter Number L011

B&V Project 60903
B&V file 32.0203
May 25, 1999

Mr. Al Linero, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

RECEIVED
MAY 26 1999
BUREAU OF
AIR REGULATION

Dear Mr. Linero:

On behalf of the Jacksonville Electric Authority (JEA), Black & Veatch is pleased to submit the enclosed CD-ROM and computer diskette containing the Prevention of Significant Deterioration Air Permit Application air dispersion modeling files and the Electronic Submittal of Application (ELSA) file for the Brandy Branch Facility. Please forward these diskettes to the appropriate parties for review. The complete permit application, with the exception of these computer disks, was previously submitted to you on May 17, 1999.

If you have any questions concerning the permit application or these computer disks, please do not hesitate to call Bert Gianazza at JEA at (904) 665-6247, or me at (913) 458-7961.

Very truly yours,

BLACK & VEATCH

Mark J. Bareta
Air Quality Scientist

mjb

cc: File

Department of
Environmental Protection

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 20, 1999

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: Jacksonville Electric Authority – Brandy Branch Project
0310485-001-AC, PSD-FL-267

Dear Mr. Worley:

Enclosed for your review and comment is an application for the above mentioned project. It consists of three simple cycle intermittent duty combustion turbines. The units are 170 megawatt General Electric PG7241FA combustion turbines with Dry Low NOx combustors.

Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850)922-6979. If you have any questions, please contact Mike Halpin at (850)921-9530.

Sincerely,

5/20

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

AAL/kt

Enclosures

cc: Mike Halpin, BAR

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 20, 1999

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

Re: Jacksonville Electric Authority – Brandy Branch Project
0310485-001-AC, PSD-FL-267

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the above mentioned project. It consists of three simple cycle intermittent duty combustion turbines. The units are 170 megawatt General Electric PG7241FA combustion turbines with Dry Low NOx combustors.

Your comments can be forwarded to my attention at the letterhead address or faxed to the Bureau at (850)922-6979. If you have any questions, please contact Mike Halpin at (850)921-9530.

Sincerely,

AAL 5/20

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

AAL/kt

Enclosures

cc: Mike Halpin, BAR

BLACK & VEATCH

8400 Ward Parkway, P.O. Box 8405, Kansas City, Missouri 64114, (913) 458-2000

JEA
Brandy Branch Project
Letter Number L009

B&V Project 60903
B&V file 32.0203
May 17, 1999

RECEIVED
MAY 19 1999
BUREAU OF
AIR REGULATION

Mr. Al Linero, P.E.
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Mail Stop 5505

0310485-001-AC
PSD-FL-267

Dear Mr. Linero:

On behalf of the Jacksonville Electric Authority (JEA), Black & Veatch is pleased to submit the enclosed Prevention of Significant Deterioration Air Permit Application for the Brandy Branch Facility. Please find four copies of the permit application enclosed with this letter, as well as a check for $7,500 for processing the permit application. A complete set of computer diskettes containing the air permit application (ELSA), and a CD ROMs containing the air dispersion modeling files are being submitted to you under separate cover.

If you have any questions concerning this permit application, please do not hesitate to call Bert Gianazza at JEA at (904) 665-6247, or me at (913) 458-7961.

Very truly yours,

BLACK & VEATCH

Mark J. Bareta
Air Quality Scientist

mjb

cc: Mike Halpin, FDEP, w/copy of the permit application
Cleve Holladay, BAR
NED
EPA
NPS
Duval Co

JEA BALDWIN SIMPLE CYCLE PROJECT

- New Brandy Branch Facility. Three dual-fuel simple cycle units.
- Prime movers are three 170 MW GE PG7241FA combustion turbines.
- Pre-application meeting in 1998, JEA proposed 15 ppm NO_X.
- We told them they could do better because CTs are identical to Duke.
- GE guaranteed 15 ppm "new and clean." Alternative pricing for 9 ppm.
- GE agreed to lower new and clean value if JEA agreed to delivery delay.
- Application received May 19. NOX at 12 ppm. 800 hours of 0.05% S oil.
- Incompleteness letter sent on May 26. Focused on hours of oil and 12 ppm.
- Response received on June 21. We have drafted another incompleteness letter.
- Do not cause or contribute to any NAAQS or increment violations.
- Okeefenokee less than 50 km away. Models showed no visibility problem.
- Parts of Okeefenokee more than 50 km away. Therefore regional haze review.
- JEA ran ISC and showed no regional haze problem.
- USFWS said they should have used higher humidity. ISC shows problems.
- USFWS said run CALPUFF "Light." Shows problems.
- USFWS says we can issue intent if JEA will run full CALPUFF.
- JEA expects no better results. It will take several months. Expensive.
- Black & Veatch, Golder, Koogler, ECT are all inexperienced.
- Meanwhile we issued Intent on almost identical TEC project at 10.5 ppm.
- Project farther from Chassahowitzka than JEA is from Okeefenokee.
- That application was received before new USFWS changes in modeling.
- JEA haze problem can be alleviated by less (daily) hours on oil.
- We met with JEA on July 15. They expect a permit about like TEC.
- They point out Brandy Branch will allow closure of Southside Units.
- Even their 0.5 percent sulfur oil comes in at less than 0.01 percent sulfur.
- Southside shutdown not contemporaneous. 0.01% oil not enforceable.
- Recommend issuance of Intent and itemization of mitigative factors.

9-25-98

Bert Gianazza JEA
Rick Tetzloff B&V
Chuck Bond JEA
Cleve
Teresa
Al
Mike

Pre-Application Meeting Agenda

JEA – Brandy Branch Combustion Turbine Project
Air Permitting Issues

1. Introductions

2. Project Overview
   A. Location
      ~ 1.5 miles northeast of Baldwin
      See Attachment 1

   B. Description
      1. Three GE 7FA class combustion turbines (~ 500 MW total)
      2. Operating in simple cycle mode only
      3. Natural gas (NG) fired with #2 fuel oil (FO) backup
      4. Base-load units (8,760 hours / year on NG, limited hours on FO)

   C. Schedule
      1. Start of Construction – July 1999
      2. Commercial Operation – January 2001

3. PSD and Other Air Requirements
   A. Attainment Status

   B. NSR / PSD Applicability
      1. New Major Source
      2. NO_X, CO, PM10 with significant emission levels

   C. BACT Issues
      1. Expected emission levels NO_X / CO
      2. PM front half catch / total condensable

   D. Air Quality Impact Analysis
      1. Air Dispersion Modeling Workplan
         a. ISCST3 model ver. 97363
         b. EPA default options / flat terrain
         c. BPIP / downwash
         d. Worst-case emissions
            - Hourly emission rates for short-term impacts
            - Annual average data for annual impacts
         e. Receptor grids
            - 10 km overall
              100m to 1km
              500m from 1 to 5 km
              1 km from 5 to 10 km
              50 m fenceline
         f. Dispersion coefficients
            Auer land use analysis / rural
         g. Meteorological data
            - JAX / Waycross 1984 - 1988

2. Modeled Predicted Impacts
    a. Significant Impact Area
        - If less than significant impact level (SIL), then done
    b. Preconstruction monitoring
    c. Ambient Air Quality Standards
        - Only if greater than SIL
    d. Increment Analysis
        - Only if greater than SIL

3. Additional Impact Analyses
    a. Commercial / Residential / Industrial Growth
    b. Vegetation & Soils
    c. Visibility
    d. Class I Analysis
        - Nearest Class I areas: Okefenokee & Wolf Island
        - VISCREEN
        - Regional Haze analysis

E. Toxics

4. PSD Application
    A. Long Form
    B. ELSA
    C. Concurrent Operating Permit
    D. Review Schedule
    E. Fees

JEA - Inlet Bleet Heat

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	173,200.	129,900.	86,600.	43,300.	182,000.	136,500.	91,000.	45,500.
Heat Rate (LHV)	Btu/kWh	9,370.	10,120.	12,190.	16,820.	10,010.	10,830.	12,780.	17,070.
Heat Cons. (LHV) X 10^6	Btu/h	1,622.9	1,314.6	1,055.7	728.3	1,821.8	1,478.3	1,163.	776.7
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	172,590.	129,290.	85,990.	42,690.	180,460.	134,960.	89,460.	43,960.
Heat Rate (LHV) Net	Btu/kWh	9,400.	10,170.	12,280.	17,060.	10,100.	10,950.	13,000.	17,670.
Exhaust Flow X 10^3	lb/h	3542.	2890.	2397.	2182.	3683.	2827.	2406.	2215.
Exhaust Temp.	Deg F.	1116.	1139.	1184.	1013.	1098.	1194.	1200.	1013.
Exhaust Heat (LHV) X 10^6	Btu/h	973.0	823.2	720.4	551.1	1011.7	865.3	744.8	562.1
Water Flow	lb/h	0.	0.	0.	0.	119,700.	90,620.	61,970.	27,170.
EMISSIONS									
NOx	ppmvd @ 15% O2	15.	15.	15.	77.	42.	42.	42.	42.
NOx AS NO2	lb/h	99.	79.	63.	220.	318.	256.	199.	131.
CO	ppmvd	15.	15.	15.	65.	20.	20.	30.	254.
CO	lb/h	48.	39.	33.	131.	65.	50.	63.	514.
UHC	ppmvw	7.	7.	7.	30.	7.	7.	7.	23.
UHC	lb/h	14.	11.	9.	36.	15.	11.	9.	28.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.
EXHAUST ANALYSIS	% VOL.								
Argon		0.89	0.90	0.90	0.90	0.86	0.84	0.86	0.90
Nitrogen		74.39	74.44	74.55	75.23	71.30	71.26	72.20	74.38
Oxygen		12.38	12.51	12.85	14.80	11.09	10.69	11.62	14.35
Carbon Dioxide		3.90	3.84	3.69	2.78	5.48	5.75	5.28	3.83
Water		8.44	8.32	8.02	6.29	11.28	11.46	10.04	6.55

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

IPS- 70600 version code- 1 . 4 . 1 Opt: 10
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JEA - Inlet Bleed Heat

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	20.	20.	20.	20.	20.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	186,500.	139,900.	93,300.	46,600.	192,700.	144,500.	96,400.	48,200.
Heat Rate (LHV)	Btu/kWh	9,310.	9,950.	11,910.	16,280.	10,040.	10,840.	12,680.	16,690.
Heat Cons. (LHV) X 10^6	Btu/h	1,736.3	1,392.	1,111.2	758.6	1,934.7	1,566.4	1,222.4	804.5
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	185,890.	139,290.	92,690.	45,990.	191,160.	142,960.	94,860.	46,660.
Heat Rate (LHV) Net	Btu/kWh	9,340.	9,990.	11,990.	16,500.	10,120.	10,960.	12,890.	17,240.
Exhaust Flow X 10^3	lb/h	3801.	3025.	2486.	2297.	3914.	2925.	2439.	2332.
Exhaust Temp.	Deg F.	1081.	1112.	1160.	966.	1068.	1183.	1200.	962.
Exhaust Heat (LHV) X 10^6	Btu/h	1036.9	863.8	751.3	569.2	1074.8	913.4	777.8	578.7
Water Flow	lb/h	0.	0.	0.	0.	130,530.	100,950.	68,710.	28,730.
EMISSIONS									
NOx	ppmvd @ 15% O2	15.	15.	15.	80.	42.	42.	42.	42.
NOx AS NO2	lb/h	106.	84.	66.	238.	338.	271.	209.	136.
CO	ppmvd	15.	15.	15.	104.	20.	20.	26.	282.
CO	lb/h	52.	41.	34.	221.	69.	51.	57.	605.
UHC	ppmvw	7.	7.	7.	47.	7.	7.	7.	27.
UHC	lb/h	15.	12.	10.	60.	15.	12.	10.	35.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.
EXHAUST ANALYSIS	% VOL.								
Argon		0.91	0.89	0.89	0.90	0.86	0.84	0.86	0.91
Nitrogen		74.99	75.00	75.11	75.86	71.77	71.48	72.40	74.99
Oxygen		12.54	12.57	12.88	15.00	11.20	10.54	11.39	14.59
Carbon Dioxide		3.90	3.89	3.75	2.77	5.49	5.89	5.48	3.78
Water		7.67	7.65	7.37	5.48	10.69	11.25	9.87	5.74

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

IPS- 70600 version code- 1 . 4 . 1 Opt: 10
ALMSTEJO 9/25/98 15:39 IBH 20F JEA.dat

JEA - Inlet Bleed Heat

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	95.	95.	95.	95.	95.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	150,500.	112,800.	75,200.	37,600.	160,100.	120,100.	80,100.	40,000.
Heat Rate (LHV)	Btu/kWh	9,760.	10,690.	12,940.	18,180.	10,240.	11,170.	13,270.	18,180.
Heat Cons. (LHV) X 10^6	Btu/h	1,468.9	1,205.8	973.1	683.6	1,639.4	1,341.5	1,062.9	727.2
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	149,890.	112,190.	74,590.	36,990.	158,560.	118,560.	78,560.	38,460.
Heat Rate (LHV) Net	Btu/kWh	9,800.	10,750.	13,050.	18,480.	10,340.	11,320.	13,530.	18,910.
Exhaust Flow X 10^3	lb/h	3254.	2691.	2265.	2064.	3365.	2693.	2318.	2089.
Exhaust Temp.	Deg F.	1144.	1170.	1200.	1043.	1133.	1200.	1200.	1053.
Exhaust Heat (LHV) X 10^6	Btu/h	901.9	776.4	679.4	527.2	936.0	810.4	701.1	540.4
Water Flow	lb/h	0.	0.	0.	0.	93,590.	69,010.	46,070.	19,720.
EMISSIONS									
NOx	ppmvd @ 15% O2	15.	15.	15.	58.	42.	42.	42.	42.
NOx AS NO2	lb/h	89.	73.	58.	156.	286.	232.	182.	123.
CO	ppmvd	15.	15.	15.	61.	20.	20.	36.	254.
CO	lb/h	43.	36.	30.	115.	59.	47.	74.	480.
UHC	ppmvw	7.	7.	7.	28.	7.	7.	7.	21.
UHC	lb/h	13.	11.	9.	33.	13.	11.	9.	25.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.
EXHAUST ANALYSIS	% VOL.								
Argon		0.87	0.86	0.86	0.87	0.84	0.84	0.85	0.86
Nitrogen		72.71	72.76	72.89	73.50	70.25	70.48	71.33	73.01
Oxygen		12.10	12.24	12.64	14.42	10.97	10.92	11.83	14.06
Carbon Dioxide		3.82	3.75	3.57	2.74	5.37	5.45	4.99	3.78
Water		10.51	10.39	10.04	8.47	12.57	12.31	11.01	8.29

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

IPS- 70600 version code- 1 . 4 . 1 Opt: 10
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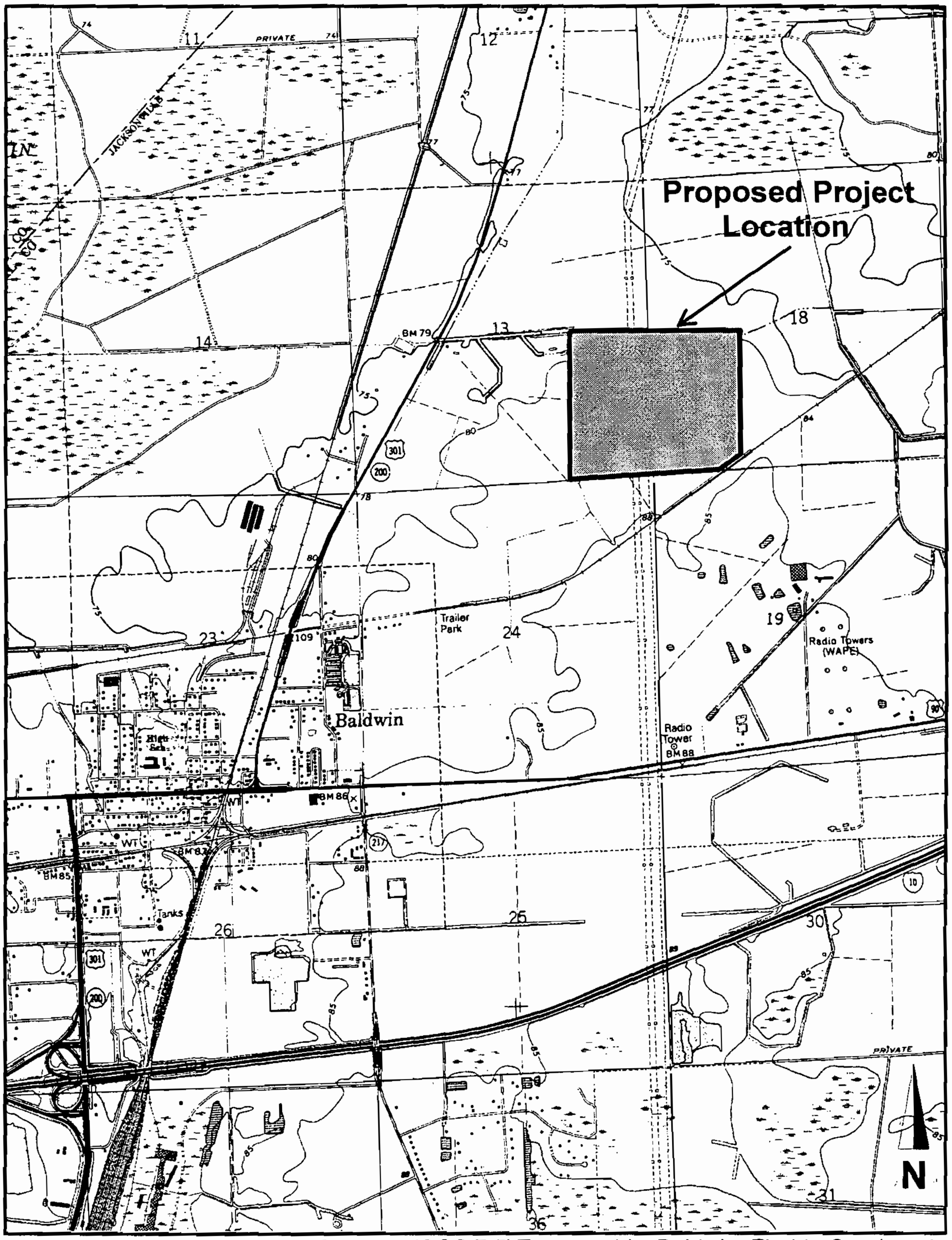

Source: USGS 7.5' Topographic, Baldwin, Florida Quadrangle

Proposed Project Location

JEASITE.SRF

RECEIVED
MAY 19 1999
BUREAU OF
AIR REGULATION

PREVENTION OF SIGNIFICANT DETERIORATION AIR PERMIT APPLICATION FOR BRANDY BRANCH FACILITY

SUBMITTED BY
Jacksonville Electric Authority

Rec'd May 19, 1999

0310485-001-AC
PSD-FI-267

PREPARED BY
Black & Veatch

May, 1999
Project No. 60903

Table of Contents

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List of Attachments

1.0 Introduction

Jacksonville Electric Authority (JEA) propose to develop a new electrical power generating station at their Brandy Branch Facility (herein after referred to as the Project) near Baldwin City, Florida. The proposed Project will be comprised of three simple cycle combustion turbines (SCCT) rated at a nominal 170 MW each, firing natural gas as the primary fuel and No. 2 distillate fuel oil as a back-up fuel. New major support facilities for the Project will include water and wastewater treatment facilities, water storage tanks, storm water detention pond, transmission line, and fuel oil storage tanks.

This report is technical support document for the Prevention of Significant Deterioration Air Permit Application. The following sections contain a project characterization, Best Available Control Technology (BACT) determination, air quality impact analysis (AQIA), and additional impact analyses designed to provide a basis for the Florida Department of Environmental Protection's (FDEP) preparation of an air construction permit for the Project.

2.0 Project Characterization

The following sections briefly characterize the Project including a general description of the location, facility, and emission units, as well as a summary of the estimated emissions and a discussion of New Source Review (NSR) applicability.

2.1 Project Location

The Project is located in the western, rural part of Duval County, Florida. Figure 2-1 shows the general location of the Project which is approximately 1 mile northeast of Baldwin City, 4 miles north-northwest of US Naval Air Station Cecil Field, and 4 miles southwest of US Naval Air Station Whitehouse Field. The nearest Federal PSD Class I Areas are the Okefenokee Wilderness Area and the Wolf Island Wilderness Area located approximately 34 km northwest and 127 km northeast of the Project, respectively.

The topography of the area is unpronounced and considered relatively flat.

2.2 Project Description

The Project will be composed of three SCCTs. Each SCCT is a General Electric 170 MW simple cycle combustion turbine (Model PG7241FA) firing natural gas as the primary fuel, with distillate fuel as back-up. The energy of the combustion gases exiting the combustor will be transformed into rotating mechanical energy as they expand through the turbine sections of the SCCTs. The rotating mechanical energy will be converted into electrical energy via a shaft on the SCCTs connected to an electrical generator. The remaining combustion gases will be exhausted to the atmosphere through an exhaust stack.

2.3 Project Emissions

This section discusses the potential to emit (PTE) of all regulated PSD air pollutants resulting from the Project. Emissions from the Project will be generated from the following emissions units:

- Three SCCTs firing natural gas as the primary fuel, with distillate fuel as back-up.
- Three No. 2 distillate fuel oil storage tanks approximately 1,000,000 gallons each.
- A diesel fired emergency fire water pump.

Figure 2-1
(Site Location)

2.3.1 SCCT Emissions

Performance data for the SCCTs, based on vendor data from GE at design loads of 50, 75, and 100 percent, natural gas and distillate fuel firing, and ambient air temperatures of 20°F, 59°F, and 95°F are provided in Attachment 1.

Ambient temperature data were selected based on meteorological data from Jacksonville, Florida. An ambient temperature of 20°F represents the winter seasonal site temperature and corresponds to maximum heat input and power generation. An ambient temperature of 59°F represents the average annual site temperature which is representative of the average heat input rate. An ambient temperature of 95°F represents the summer seasonal site temperature and corresponds to the lowest heat input rate for the combustion.

The maximum pound per hour emission rates considering all ambient temperatures and partial load operation for natural gas and distillate fuel oil firing are presented in Table 2-1.

2.3.2 No. 2 Distillate Fuel Oil Storage Tank

The three fuel oil storage tanks are estimated to have a capacity of 1,000,000 gallons each. Emissions of VOCs from the fuel oil storage tank were estimated using the EPA's TANKS (Ver. 3.1) program. Results of the TANKS emission modeling are included in Attachment 2. The VOC emissions from the fuel oil storage tanks are approximately 0.83 tpy and are included in the total Project's PTE calculations.

2.4 Maximum Project Potential to Emit

The potential to emit was estimated from the maximum hourly emission rate for each pollutant at an ambient temperature of 59°F (average annual) considering 50 to 100 percent load simple cycle operation, and 800 hours of distillate fuel oil firing (0.05 % sulfur) with 4,000 hour a year of natural gas firing. The Project's potential to emit for each pollutant is summarized in Table 2-2. The applicable PSD significant emission levels for each pollutant are included for reference purposes in the table, and a spreadsheet used to calculate the potential to emit is included in Attachment 3.

2.5 New Source Review Applicability

The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications under two programs; the PSD program outlined in 40 CFR 52.21, and the Nonattainment NSR program outlined in 40 CFR 51 and 52. The proposed facility is in an attainment area with respect to all pollutants. As such, the PSD

Table 2-1 Project Maximum Emission Rates (lb/h)*		
Pollutant	Natural Gas Firing (lb/h)	Distillate Oil Firing (lb/h)
NOx	84.8	338.0
SO2	1.1	104.3
CO	52.0	74.0
PM/PM10	9.0	17.0
VOC	3.0	3.0

*Maximum pound per hour emission rates for the SCCTs considering average ambient temperature and partial load operation for natural gas and distillate fuel oil firing.

Table 2-2
PSD Applicability

Pollutant	Project PTE (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NOx	857.7[a]	40	**yes**
SO_2	124.3[a,b]	40	**yes**
CO	366.2[a]	100	**yes**
PM/PM_{10}	74.5[a,c]	25/15	**yes**
VOC	21.3[a,f]	40	no
Sulfuric Acid Mist	15.2[a,d]	7	**yes**
Total Reduced Sulfur	negl.	10	no
Hydrogen Sulfide	negl.	10	no
Vinyl Chloride	negl.	1	no
Total Fluorides	negl.	3	no
Mercury	0.0007[e]	0.1	no
Beryllium	0.0002[e]	0.0004	no
Lead	0.042[e]	0.6	no

[a]Based on maximum lb/h emission rate at 59°F conditions for all loads and operating scenarios; assuming 4,000 and 800 hours per year of natural gas and distillate fuel oil firing, respectively.

[b]Based on 0.05% sulfur distillate fuel oil, 0.2 gr/100 scf sulfur natural gas, and assuming 100 percent conversion to SO_2.

[c]Assumes front half PM/PM_{10} emissions.

[d]Conservatively assuming a 10 percent conversion of SO2 to SO3, and a molecular ratio of 1.22 from SO3 to H2SO4.

[e]Based on AP-42 emission factors, a maximum heat input of 1,934.7 MBtu/h and distillate fuel oil firing for 800 hours per year.

[f]VOC PTE is based on potential emissions from the Project's combustion sources and emissions from the fuel oil storage tanks.

Note: PTE calculations are provided in a spreadsheet included in Attachment 3.

program will apply to the Project, as administered by the state of Florida under 62-212.400, F.A.C., Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration.

2.5.1 Prevention of Significant Deterioration

The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the ambient air quality standards (AAQS) while providing a margin for future industrial and commercial growth. PSD regulations apply to major stationary sources and major modifications at major existing sources undergoing construction in areas designated as attainment or unclassifiable.

A major stationary source is defined as any one of the listed major source categories which emits, or has the potential to emit, 100 tpy or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the facility is not one of the listed major source categories. The Brandy Branch Facility is not one of the 28 major source categories but does has a PTE greater than 250 tpy for at least one regulated pollutant. Additionally, the estimated emissions of NO_x, SO_2, CO, PM/PM_{10}, and sulfuric acid mist (SAM) resulting from the proposed Project, exceed the PSD significant emissions levels of 40, 40, 100, 25/15, and 7 tpy, respectively. Therefore, the Project's emissions of NO_x, SO_2, CO, and PM/ PM_{10}, and SAM are subject to PSD review as a new major source. The PSD review includes a BACT analysis, air quality impact analysis (AQIA), and an assessment of the total project's impact on general commercial, residential, and commercial growth, soils and vegetation, and visibility, as well as a Class I impact analysis.

3.0 Best Available Control Technology

A best available control technology (BACT) analysis for Brandy Branch has been included as Attachment 4.

4.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the PSD air quality impact analysis for those pollutants, which will have a PTE greater than the PSD significant emission rate (i.e., NO_x, SO_2, CO, and PM/PM_{10}). (SAM emissions are discussed in the BACT, Section 3.0, but were not assessed in the application). The air dispersion modeling analysis was conducted in accordance with EPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon air dispersion modeling protocol submitted to FDEP on behalf of JEA in a memorandum from Black & Veatch dated November 20, 1998 (Attachment 5).

4.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3 Version 98356) air dispersion model was used to predict maximum ground level concentrations associated with the Project emissions. The ISCST3 model is an EPA approved, steady-state, straight-line Gaussian plume model, which may be used to access pollutant concentrations from a wide variety of sources associated with an industrial source complex. In addition, ISCST3, unlike its predecessors, incorporates the COMPLEX1 dispersion algorithm for determining intermediate and complex terrain concentration impacts in accordance with EPA guidance.

4.2 Model Input and Options

This section discusses the model input parameters, source and emission parameters, and the ISCST3 model default options and input databases.

4.2.1 Model Input Source Parameters

The ISCST3 model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, fuels (i.e., natural gas and distillate fuel oil), and ambient temperatures. This was accomplished by representing each SCCT unit's proposed operating load range (i.e., 50, 75, and 100 percent loads) with a worst-case set of stack parameters and pollutant emission rates that were conservatively selected from vendor performance data to produce the worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as "enveloping".

The worst-case representative stack parameters and emission rates for each load, fuel type, and ambient temperature considered in the analysis are presented in Table 4-1. A spreadsheet used in determining the load based representative emissions and stack parameters from the vendor performance data is included in Attachment 3.

4.2.2 Land Use Dispersion Coefficient Determination

The EPA's land use method was used to determine whether rural or urban dispersion coefficients should be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3 km radius of the site was classified as rural or urban using the Auer land use classification method. Based on a visual inspection of the USGS 7.5 minute topographic map of the proposed Project's location, it was concluded that over 50 percent of the area surrounding the Project is classified as rural. Accordingly, the rural dispersion modeling option was used in the ISCST3 air dispersion modeling.

4.2.3 GEP Stack Height Determination

The Project's proposed buildings and structures were analyzed to determine their potential to influence the dispersion of stack emissions. EPA's Guideline for Determination of Good Engineering Practice Stack Height guidance document was followed in this evaluation. Structure dimensions and relative locations were entered into EPA's Building Profile Input Program (BPIP) to produce an ISCST3 input file with the proper Huber-Snyder or Schulman-Scire direction specific building downwash parameters. The BPIP formula GEP height for each SCCT is 32.8 m (107.6 ft).

4.2.4 Model Defaults

The following standard USEPA default regulatory modeling options were initialized in the ISCST3 air dispersion modeling:

- Final plume rise.
- Stack-tip downwash.
- Buoyancy induced dispersion.
- Default vertical wind profile exponents and vertical potential temperature gradient values.
- Calm processing option.
- Flat terrain option.

Table 4-1
Representative (*Enveloped*) Stack Parameters and Pollutant Emissions Used in ISCST3 Modeling Analysis

Operating Scenario/Fuel	ISCST3 Source ID[a]	Load	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)			
							NO_x	SO_2	CO	PM/PM_{10}[d]
SCCT Natural Gas	SNG1	100	27.43	5.49	45.04	855.93	13.36	0.14	6.55	1.13
	SNG7	75	27.43	5.49	37.85	873.15	10.58	0.12	5.17	1.13
	SNG5	50	27.43	5.49	32.42	899.82	8.32	0.09	4.28	1.13
SCCT Distillate Fuel Oil	SFO1	100	27.43	5.49	46.27	848.71	42.59	13.14	8.69	2.14
	SFO7	75	27.43	5.49	38.54	912.59	34.14	10.64	6.43	2.14
	SFO5	50	27.43	5.49	33.06	922.04	26.33	8.30	9.32	2.14
SCCT Annualized[b]	A1T	100	27.43	5.49	47.78	875.37	6.70	1.19	N/A	0.57
	A7T	75	27.43	5.49	39.54	888.15	5.36	0.97	N/A	0.57
	A5T	50	27.43	5.49	33.69	913.15	4.25	0.76	N/A	0.57
Diesel Fire Pump[d]	SFP	N/A	7.32	0.15	60.02	615.93	N/A	0.004	0.002	0.004
	AFP	N/A	7.32	0.15	60.02	615.93	0.009	0.0006	N/A	0.0006

[a]S or A refer to short-term or annualized emission rate; NG or FO refer to natural gas or distillate fuel oil fired; 1,7,or 5 refer to 100, 75, or 50 percent load; and T refers to total emission sources.

[b]Annualized emission rate based on 4,000 hours of natural gas firing and 800 hours of distillate fuel oil firing.

[c]Assumes front half PM/PM_{10} Emissions.

[d]Assumes the diesel fire pump operates 52 hours per year for testing purposes.

4.2.5 Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 10 km from the center of the proposed Project was used. The rectangular grid network consists of 100 m spacing from the proposed fenceline out to 2 km, 250 m spacing from 2 to 5 km, 500 m spacing from 5 to 7 km, and then 1,000 m spacing from 7 to 10 km. Receptor spacing of 50 m intervals was used along the Project's fenceline, and a 100 m fine grid was used at the maximum impact receptors. Figure 4-1 illustrates the nested rectangular grid, fence line receptors, and the relative location of the emission sources and downwash structures. The flat terrain option was used for all receptor points.

4.2.6 Meteorological Data

The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. Five years (1984-1988) of surface and upper air meteorological data from Jacksonville, Florida and Waycross, Georgia, respectively, were used in the ISCST3 air dispersion modeling analysis. These meteorological data were downloaded from EPA's SCRAM web site and processed with PCRAMMET to combine the surface and mixing height data, interpolate hourly mixing heights from the twice-daily mixing heights, and calculate atmospheric stability class.

4.3 Model Results

As presented in Section 2.0, the Project's PTE exceeds the PSD significant emission thresholds for NO_x, SO_2, CO, and PM/PM_{10}. In accordance with the approved modeling protocol, ISCST3 air dispersion modeling was performed (as described in the preceding sections) using the enveloped emission rates for NO_x, SO_2, CO, and PM/PM_{10} for each applicable averaging period.

Tables 4-2 through 4-9 present the results for the 5 year refined modeling period (1984-1988) for each pollutant and applicable averaging period. The underlined concentrations in each table represent the maximum modeled predicted impacts in each case.

Figure 4-1
(Receptor Location Plot)

Table 4-2
ISCST3 Model Predicted Maximum Annual Concentrations of NO_x

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
A1T	Annual	100	1984	0.54	408,892.0	3,354,573.5
A7T		75		0.54	408,892.0	3,354,573.5
A5T		50		0.54	408,892.0	3,354,573.5
A1T		100	1985	0.57	408,892.0	3,354,573.5
A7T		75		0.57	408,892.0	3,354,573.5
A5T		50		0.57	408,892.0	3,354,573.5
A1T		100	1986	0.58	408,892.0	3,354,573.5
A7T		75		0.58	408,892.0	3,354,573.5
A5T		50		0.58	408,892.0	3,354,573.5
A1T		100	1987	0.51	408,892.0	3,354,573.5
A7T		75		0.51	408,892.0	3,354,573.5
A5T		50		0.51	408,892.0	3,354,573.5
A1T		100	1988	0.52	408,892.0	3,354,573.5
A7T		75		0.52	408,892.0	3,354,573.5
A5T		50		0.52	408,892.0	3,354,573.5

Table 4-3
ISCST3 Model Predicted Maximum Annual Concentrations of SO_2

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
A1T	Annual	100	1984	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1985	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1986	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1987	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1988	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5

Table 4-4
ISCST3 Model Predicted Maximum 3-Hour Concentrations of SO_2

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
SNG1	3-Hour	100	1984	13.36	408,892.0	3,354,573.5
SNG7		75		13.36	408,892.0	3,354,573.5
SNG5		50		13.36	408,892.0	3,354,573.5
SNG1		100	1985	12.32	408,892.0	3,354,573.5
SNG7		75		12.32	408,892.0	3,354,573.5
SNG5		50		12.32	408,892.0	3,354,573.5
SNG1		100	1986	14.88	408,892.0	3,354,573.5
SNG7		75		14.88	408,892.0	3,354,573.5
SNG5		50		14.88	408,892.0	3,354,573.5
SNG1		100	1987	11.45	408,892.0	3,354,573.5
SNG7		75		11.45	408,892.0	3,354,573.5
SNG5		50		11.45	408,892.0	3,354,573.5
SNG1		100	1988	9.26	408,892.0	3,354,573.5
SNG7		75		9.26	408,892.0	3,354,573.5
SNG5		50		9.26	408,892.0	3,354,573.5
SFO1	3-Hour	100	1984	13.36	408,892.0	3,354,573.5
SFO7		75		13.36	408,892.0	3,354,573.5
SFO5		50		13.36	408,892.0	3,354,573.5
SFO1		100	1985	12.32	408,892.0	3,354,573.5
SFO7		75		12.32	408,892.0	3,354,573.5
SFO5		50		12.32	408,892.0	3,354,573.5
SFO1		100	1986	14.88	408,892.0	3,354,573.5
SFO7		75		14.88	408,892.0	3,354,573.5
SFO5		50		14.88	408,892.0	3,354,573.5
SFO1		100	1987	11.45	408,892.0	3,354,573.5
SFO7		75		11.45	408,892.0	3,354,573.5
SFO5		50		11.45	408,892.0	3,354,573.5
SFO1		100	1988	9.26	408,892.0	3,354,573.5
SFO7		75		9.26	408,892.0	3,354,573.5
SFO5		50		9.26	408,892.0	3,354,573.5

Table 4-5
ISCST3 Model Predicted Maximum 24-Hour Concentrations of SO_2

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
SNG1	24-Hour	100	1984	3.35	408,941.9	3,354,579.0
SNG7		75		3.35	408,941.9	3,354,579.0
SNG5		50		3.35	408,941.9	3,354,579.0
SNG1		100	1985	4.22	408,892.0	3,354,573.5
SNG7		75		4.22	408,892.0	3,354,573.5
SNG5		50		4.22	408,892.0	3,354,573.5
SNG1		100	1986	3.55	408,892.0	3,354,573.5
SNG7		75		3.55	408,892.0	3,354,573.5
SNG5		50		3.55	408,892.0	3,354,573.5
SNG1		100	1987	3.57	408,892.0	3,354,573.5
SNG7		75		3.57	408,892.0	3,354,573.5
SNG5		50		3.57	408,892.0	3,354,573.5
SNG1		100	1988	2.20	408,892.0	3,354,573.5
SNG7		75		2.20	408,892.0	3,354,573.5
SNG5		50		2.20	408,892.0	3,354,573.5
SFO1	24-Hour	100	1984	3.36	408,941.9	3,354,579.0
SFO7		75		3.36	408,941.9	3,354,579.0
SFO5		50		3.35	408,941.9	3,354,579.0
SFO1		100	1985	4.22	408,892.0	3,354,573.5
SFO7		75		4.22	408,892.0	3,354,573.5
SFO5		50		4.22	408,892.0	3,354,573.5
SFO1		100	1986	3.55	408,892.0	3,354,573.5
SFO7		75		3.55	408,892.0	3,354,573.5
SFO5		50		3.55	408,892.0	3,354,573.5
SFO1		100	1987	3.57	408,892.0	3,354,573.5
SFO7		75		3.57	408,892.0	3,354,573.5
SFO5		50		3.57	408,892.0	3,354,573.5
SFO1		100	1988	2.20	408,892.0	3,354,573.5
SFO7		75		2.20	408,892.0	3,354,573.5
SFO5		50		2.20	408,892.0	3,354,573.5

Table 4-6
ISCST3 Model Predicted Maximum 1-Hour Concentrations of CO

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
SNG1	1-Hour	100	1984	10.78	408,892.0	3,354,573.5
SNG7		75		10.78	408,892.0	3,354,573.5
SNG5		50		10.78	408,892.0	3,354,573.5
SNG1		100	1985	10.78	408,892.0	3,354,573.5
SNG7		75		10.78	408,892.0	3,354,573.5
SNG5		50		10.78	408,892.0	3,354,573.5
SNG1		100	1986	10.78	408,892.0	3,354,573.5
SNG7		75		10.78	408,892.0	3,354,573.5
SNG5		50		10.78	408,892.0	3,354,573.5
SNG1		100	1987	10.78	408,892.0	3,354,573.5
SNG7		75		10.78	408,892.0	3,354,573.5
SNG5		50		10.78	408,892.0	3,354,573.5
SNG1		100	1988	10.30	408,892.0	3,354,573.5
SNG7		75		10.30	408,892.0	3,354,573.5
SNG5		50		10.30	408,892.0	3,354,573.5
SFO1	1-Hour	100	1984	10.78	408,892.0	3,354,573.5
SFO7		75		10.78	408,892.0	3,354,573.5
SFO5		50		10.78	408,892.0	3,354,573.5
SFO1		100	1985	10.78	408,892.0	3,354,573.5
SFO7		75		10.78	408,892.0	3,354,573.5
SFO5		50		10.78	408,892.0	3,354,573.5
SFO1		100	1986	10.78	408,892.0	3,354,573.5
SFO7		75		10.78	408,892.0	3,354,573.5
SFO5		50		10.78	408,892.0	3,354,573.5
SFO1		100	1987	10.78	408,892.0	3,354,573.5
SFO7		75		10.78	408,892.0	3,354,573.5
SFO5		50		10.78	408,892.0	3,354,573.5
SFO1		100	1988	10.30	408,892.0	3,354,573.5
SFO7		75		10.30	408,892.0	3,354,573.5
SFO5		50		10.30	408,892.0	3,354,573.5

Table 4-7
ISCST3 Model Predicted Maximum 8-Hour Concentrations of CO

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
SNG1	8-Hour	100	1984	3.79	408,941.9	3,354,579.0
SNG7		75		3.79	408,941.9	3,354,579.0
SNG5		50		3.79	408,941.9	3,354,579.0
SNG1		100	1985	2.77	408,892.0	3,354,573.5
SNG7		75		2.77	408,892.0	3,354,573.5
SNG5		50		2.77	408,892.0	3,354,573.5
SNG1		100	1986	4.64	408,892.0	3,354,573.5
SNG7		75		4.64	408,892.0	3,354,573.5
SNG5		50		4.64	408,892.0	3,354,573.5
SNG1		100	1987	2.98	408,892.0	3,354,573.5
SNG7		75		2.98	408,892.0	3,354,573.5
SNG5		50		2.98	408,892.0	3,354,573.5
SNG1		100	1988	2.41	408,892.0	3,354,573.5
SNG7		75		2.41	408,892.0	3,354,573.5
SNG5		50		2.41	408,892.0	3,354,573.5
SFO1	8-Hour	100	1984	3.79	408,941.9	3,354,579.0
SFO7		75		3.79	408,941.9	3,354,579.0
SFO5		50		3.79	408,941.9	3,354,579.0
SFO1		100	1985	2.77	408,892.0	3,354,573.5
SFO7		75		2.77	408,892.0	3,354,573.5
SFO5		50		2.77	408,892.0	3,354,573.5
SFO1		100	1986	4.64	408,892.0	3,354,573.5
SFO7		75		4.64	408,892.0	3,354,573.5
SFO5		50		4.64	408,892.0	3,354,573.5
SFO1		100	1987	2.98	408,892.0	3,354,573.5
SFO7		75		2.98	408,892.0	3,354,573.5
SFO5		50		2.98	408,892.0	3,354,573.5
SFO1		100	1988	2.41	408,892.0	3,354,573.5
SFO7		75		2.41	408,892.0	3,354,573.5
SFO5		50		2.41	408,892.0	3,354,573.5

Table 4-8
ISCST3 Model Predicted Maximum Annual Concentrations of PM/PM_{10}

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
A1T	Annual	100	1984	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1985	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1986	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1987	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5
A1T		100	1988	0.04	408,892.0	3,354,573.5
A7T		75		0.04	408,892.0	3,354,573.5
A5T		50		0.04	408,892.0	3,354,573.5

Table 4-9
ISCST3 Model Predicted Maximum 24-Hour Concentrations of PM/PM_{10}

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	UTM Location	
					East (m)	North (m)
SNG1	24-Hour	100	1984	3.32	408,941.9	3,354,579.0
SNG7		75		3.32	408,941.9	3,354,579.0
SNG5		50		3.32	408,941.9	3,354,579.0
SNG1		100	1985	4.18	408,892.0	3,354,573.5
SNG7		75		4.18	408,892.0	3,354,573.5
SNG5		50		4.18	408,892.0	3,354,573.5
SNG1		100	1986	3.51	408,892.0	3,354,573.5
SNG7		75		3.51	408,892.0	3,354,573.5
SNG5		50		3.51	408,892.0	3,354,573.5
SNG1		100	1987	3.53	408,892.0	3,354,573.5
SNG7		75		3.53	408,892.0	3,354,573.5
SNG5		50		3.53	408,892.0	3,354,573.5
SNG1		100	1988	2.17	408,892.0	3,354,573.5
SNG7		75		2.17	408,892.0	3,354,573.5
SNG5		50		2.17	408,892.0	3,354,573.5
SFO1	24-Hour	100	1984	3.32	408,941.9	3,354,579.0
SFO7		75		3.32	408,941.9	3,354,579.0
SFO5		50		3.32	408,941.9	3,354,579.0
SFO1		100	1985	4.18	408,892.0	3,354,573.5
SFO7		75		4.18	408,892.0	3,354,573.5
SFO5		50		4.18	408,892.0	3,354,573.5
SFO1		100	1986	3.51	408,892.0	3,354,573.5
SFO7		75		3.51	408,892.0	3,354,573.5
SFO5		50		3.51	408,892.0	3,354,573.5
SFO1		100	1987	3.53	408,892.0	3,354,573.5
SFO7		75		3.53	408,892.0	3,354,573.5
SFO5		50		3.53	408,892.0	3,354,573.5
SFO1		100	1988	2.17	408,892.0	3,354,573.5
SFO7		75		2.17	408,892.0	3,354,573.5
SFO5		50		2.17	408,892.0	3,354,573.5

4.3.1 Comparison to PSD Significant Impact Levels and Pre-Construction Monitoring Requirements

Table 4-7 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels and the pre-construction monitoring requirements. As Table 4-7 indicates, the Project's maximum predicted concentrations are less than the PSD Class II significant impact levels (SILs) for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and AAQS analyses) are required.

Additionally, the maximum predicted concentrations are less than the pre-construction monitoring de minimis levels for each pollutant and applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD pre-construction monitoring requirements.

Table 4-10
Comparison of Maximum Predicted Impacts with the PSD Class II Significant Impact Levels and the PSD De Minimis Monitoring Levels

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class II Significant Impact Level	PSD De Minimis Monitoring Level
NO_x	Annual	0.58	1	14
SO_2	Annual	0.04	1	-
	3-Hour	14.88	25	-
	24-Hour	4.22	5	13
CO	1-Hour	10.78	2,000	-
	8-Hour	4.64	500	575
PM/PM_{10}	Annual	0.04	1	-
	24-Hour	4.18	5	10

5.0 Additional and Class I Area Impact Analyses

The following sections discuss the Project's impacts on commercial, residential, and industrial growth, vegetation and soils, visibility, and nearby Class I areas.

5.1 Commercial, Residential, and Industrial Growth

The Project is at the new electrical power generating station Brandy Branch Facility near Baldwin City within Duval County. There will be an increase in the local labor force during the construction phase of the Project, but this increase will be temporary, short-lived, and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the project.

It is anticipated that most of the labor force during the construction phase will commute from nearby communities. The electrical generating capacity created by the Project will not have a significant effect upon the industrial growth in the immediate area considering that the electrical generating capacity will be sold to the grid as opposed to a nearby industrial host.

Population increase is a secondary growth indicator of potential increases in air quality levels. Changes in air quality due to population increase are related to the amount of vehicle traffic, commercial/institutional facilities, and home fuel use. The net number of new, permanent jobs which will be created by the Project is estimated to be six. It can be concluded that the air quality impacts associated with secondary growth will not be significant because the increase in population due to the operation of the proposed facility will be very small, compared to the overall population size of the surrounding area.

5.2 Vegetation and Soils

Combustion turbine projects are typically considered "clean facilities" that have very low predicted ground level pollutant impacts. The low predicted impacts are the direct result of complete combustion and very effective pollutant dispersion. Dispersion is enhanced by the thermal and momentum buoyancy characteristics of the combustion turbine exhaust. Therefore, the project's impacts on soils and vegetation will be minimal.

The NAAQS were established to protect public health and welfare from any adverse effects of air pollutants. The definition of public welfare also encompasses vegetation and soils. Specifically, ambient concentrations of NO_2, SO_2, CO, and PM/PM_{10} below the secondary NAAQS will not result in harmful effects for most types of soils and vegetation.

The criteria pollutants, which triggered an additional impact analysis, include NO_x,

SO_2, CO, and PM/PM_{10}. The modeled impacts were compared to the secondary NAAQS as the basis for assessing cumulative impacts. The modeling in Section 4.0 showed that the NO_x, SO_2, CO, and PM/PM_{10} impacts are below the NAAQS. The impacts are even less than the much lower significant impact level thresholds. Because the Project's emissions do not even significantly impact the NAAQS, it is reasonable to conclude that no adverse effects on soils and vegetation will occur.

5.3 Class I Area Impact Analysis

Class I areas are afforded special attention based on their value from a natural, scenic, recreational, or historic perspective. Emission sources subject to PSD review are analyzed to determine their potential for deteriorating the particular properties that make these areas worthy of their Class I designation. These properties are known as air quality related values (AQRVs), and typically include such attributes as flora and fauna, visibility, and scenic value.

The Project is located approximately 34 km southeast and 127 km southwest of Federal PSD Class I Areas the Okefenokee Wilderness Area and Wolf Island Wilderness Area, respectively. The areas are designated as mandatory Class I areas, under the jurisdiction of the Fish and Wildlife Service as their Federal Land Manager (FLM). The FLM typically establishes indicators and thresholds to measure a source's potential for impacting the AQRV's of a Class I area. These indicators are typically measured by assessing the project's impact on air the quality and visibility/regional haze.

5.3.1 Class I Air Quality Impact Analysis and Results

Air dispersion modeling was performed to determine the Project's maximum predicted impact at the Class I areas. The ISCST3 air dispersion model was used in the flat terrain mode to determine the maximum predicted impacts of NO_x, SO_2, and PM/PM_{10} at a receptor placed at the closest boundary point of the Wilderness Areas. The 5 year meteorological data set, model options, and operating scenarios used in the refined modeling analysis presented in Section 4.0, were also used in the Class I air quality impact analyses.

Tables 5-1 through 5-12 presents the results of the Class I areas air dispersion modeling for each pollutant and applicable averaging period. The maximum predicted concentrations are presented for each year and compared with the Class I SILs. The Class I SILs were calculated as 4 percent of the PSD Class I increments. As the results in Table 5-13 indicate, the maximum predicted

Table 5-1
ISCST3 Model Predicted Maximum Annual Concentrations of NO_x at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
A1T	Annual	100	1984	0.01	2.5	0.1
A7T		75		0.01	2.5	0.1
A5T		50		0.01	2.5	0.1
A1T		100	1985	0.01	2.5	0.1
A7T		75		0.01	2.5	0.1
A5T		50		0.01	2.5	0.1
A1T		100	1986	0.01	2.5	0.1
A7T		75		0.01	2.5	0.1
A5T		50		0.01	2.5	0.1
A1T		100	1987	0.01	2.5	0.1
A7T		75		0.01	2.5	0.1
A5T		50		0.01	2.5	0.1
A1T		100	1988	0.01	2.5	0.1
A7T		75		0.01	2.5	0.1
A5T		50		0.01	2.5	0.1

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-2
ISCST3 Model Predicted Maximum Annual Concentrations
of NO_x at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m³)	Class I Increment (µg/m³)	Class I SIL* (µg/m³)
A1T	Annual	100	1984	0.004	2.5	0.1
A7T		75		0.004	2.5	0.1
A5T		50		0.003	2.5	0.1
A1T		100	1985	0.004	2.5	0.1
A7T		75		0.004	2.5	0.1
A5T		50		0.003	2.5	0.1
A1T		100	1986	0.005	2.5	0.1
A7T		75		0.004	2.5	0.1
A5T		50		0.004	2.5	0.1
A1T		100	1987	0.003	2.5	0.1
A7T		75		0.003	2.5	0.1
A5T		50		0.003	2.5	0.1
A1T		100	1988	0.004	2.5	0.1
A7T		75		0.003	2.5	0.1
A5T		50		0.003	2.5	0.1

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-3
ISCST3 Model Predicted Maximum Annual Concentrations
of SO_2 at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
A1T	Annual	100	1984	0.002	2	0.08
A7T		75		0.002	2	0.08
A5T		50		0.002	2	0.08
A1T		100	1985	0.002	2	0.08
A7T		75		0.001	2	0.08
A5T		50		0.001	2	0.08
A1T		100	1986	0.002	2	0.08
A7T		75		0.002	2	0.08
A5T		50		0.001	2	0.08
A1T		100	1987	0.001	2	0.08
A7T		75		0.001	2	0.08
A5T		50		0.001	2	0.08
A1T		100	1988	0.002	2	0.08
A7T		75		0.002	2	0.08
A5T		50		0.002	2	0.08

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-4
ISCST3 Model Predicted Maximum Annual Concentrations of SO_2 at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
A1T	Annual	100	1984	0.0010	2	0.08
A7T		75		0.0010	2	0.08
A5T		50		0.0010	2	0.08
A1T		100	1985	0.0010	2	0.08
A7T		75		0.0010	2	0.08
A5T		50		0.0004	2	0.08
A1T		100	1986	0.0007	2	0.08
A7T		75		0.0006	2	0.08
A5T		50		0.0006	2	0.08
A1T		100	1987	0.0005	2	0.08
A7T		75		0.0004	2	0.08
A5T		50		0.0004	2	0.08
A1T		100	1988	0.0005	2	0.08
A7T		75		0.0005	2	0.08
A5T		50		0.0004	2	0.08

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-5 ISCST3 Model Predicted Maximum 3-Hour Concentrations of SO_2 at Okefenokee						
ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
SNG1	3-Hour	100	1984	0.02	25	1
SNG7		75		0.02	25	1
SNG5		50		0.01	25	1
SNG1		100	1985	0.02	25	1
SNG7		75		0.02	25	1
SNG5		50		0.02	25	1
SNG1		100	1986	0.02	25	1
SNG7		75		0.02	25	1
SNG5		50		0.02	25	1
SNG1		100	1987	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SNG1		100	1988	0.02	25	1
SNG7		75		0.02	25	1
SNG5		50		0.02	25	1
SFO1	3-Hour	100	1984	**1.17**	25	1
SFO7		75		**1.10**	25	1
SFO5		50		0.99	25	1
SFO1		100	1985	**1.64**	25	1
SFO7		75		**1.49**	25	1
SFO5		50		**1.29**	25	1
SFO1		100	1986	**1.19**	25	1
SFO7		75		**1.08**	25	1
SFO5		50		0.95	25	1
SFO1		100	1987	**1.13**	25	1
SFO7		75		**1.03**	25	1
SFO5		50		0.91	25	1
SFO1		100	1988	**1.98**	25	1
SFO7		75		**1.81**	25	1
SFO5		50		**1.58**	25	1

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-6 ISCST3 Model Predicted Maximum 3-Hour Concentrations of SO_2 at Wolf Island						
ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m³)	Class I Increment (µg/m³)	Class I SIL* (µg/m³)
SNG1	3-Hour	100	1984	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SNG1		100	1985	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SNG1		100	1986	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SNG1		100	1987	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SNG1		100	1988	0.01	25	1
SNG7		75		0.01	25	1
SNG5		50		0.01	25	1
SFO1	3-Hour	100	1984	0.83	25	1
SFO7		75		0.73	25	1
SFO5		50		0.62	25	1
SFO1		100	1985	0.71	25	1
SFO7		75		0.62	25	1
SFO5		50		0.52	25	1
SFO1		100	1986	0.84	25	1
SFO7		75		0.74	25	1
SFO5		50		0.64	25	1
SFO1		100	1987	0.86	25	1
SFO7		75		0.79	25	1
SFO5		50		0.69	25	1
SFO1		100	1988	0.45	25	1
SFO7		75		0.41	25	1
SFO5		50		0.36	25	1

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-7
ISCST3 Model Predicted Maximum 24-Hour Concentrations
of SO_2 at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
SNG1	24-Hour	100	1984	0.005	5	0.2
SNG7		75		0.005	5	0.2
SNG5		50		0.004	5	0.2
SNG1		100	1985	0.004	5	0.2
SNG7		75		0.004	5	0.2
SNG5		50		0.003	5	0.2
SNG1		100	1986	0.005	5	0.2
SNG7		75		0.004	5	0.2
SNG5		50		0.004	5	0.2
SNG1		100	1987	0.004	5	0.2
SNG7		75		0.004	5	0.2
SNG5		50		0.003	5	0.2
SNG1		100	1988	0.006	5	0.2
SNG7		75		0.006	5	0.2
SNG5		50		0.005	5	0.2
SFO1	24-Hour	100	1984	**0.420**	5	0.2
SFO7		75		**0.380**	5	0.2
SFO5		50		**0.320**	5	0.2
SFO1		100	1985	**0.280**	5	0.2
SFO7		75		**0.240**	5	0.2
SFO5		50		**0.210**	5	0.2
SFO1		100	1986	**0.330**	5	0.2
SFO7		75		**0.310**	5	0.2
SFO5		50		**0.280**	5	0.2
SFO1		100	1987	**0.360**	5	0.2
SFO7		75		**0.320**	5	0.2
SFO5		50		**0.270**	5	0.2
SFO1		100	1988	**0.340**	5	0.2
SFO7		75		**0.360**	5	0.2
SFO5		50		**0.330**	5	0.2

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-8
ISCST3 Model Predicted Maximum 24-Hour Concentrations of SO_2 at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	Class I Increment (μg/m^3)	Class I SIL* (μg/m^3)
SNG1	24-Hour	100	1984	0.003	5	0.2
SNG7		75		0.003	5	0.2
SNG5		50		0.002	5	0.2
SNG1		100	1985	0.001	5	0.2
SNG7		75		0.001	5	0.2
SNG5		50		0.001	5	0.2
SNG1		100	1986	0.001	5	0.2
SNG7		75		0.001	5	0.2
SNG5		50		0.001	5	0.2
SNG1		100	1987	0.002	5	0.2
SNG7		75		0.001	5	0.2
SNG5		50		0.001	5	0.2
SNG1		100	1988	0.001	5	0.2
SNG7		75		0.001	5	0.2
SNG5		50		0.001	5	0.2
SFO1	24-Hour	100	1984	**0.220**	5	0.2
SFO7		75		**0.200**	5	0.2
SFO5		50		0.170	5	0.2
SFO1		100	1985	0.130	5	0.2
SFO7		75		0.110	5	0.2
SFO5		50		0.090	5	0.2
SFO1		100	1986	0.110	5	0.2
SFO7		75		0.010	5	0.2
SFO5		50		0.080	5	0.2
SFO1		100	1987	0.120	5	0.2
SFO7		75		0.110	5	0.2
SFO5		50		0.120	5	0.2
SFO1		100	1988	0.120	5	0.2
SFO7		75		0.100	5	0.2
SFO5		50		0.080	5	0.2

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-9 ISCST3 Model Predicted Maximum Annual Concentrations of PM/PM_{10} at Okefenokee						
ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (µg/m³)	Class I Increment (µg/m³)	Class I SIL* (µg/m³)
A1T	Annual	100	1984	0.001	4	0.16
A7T		75		0.001	4	0.16
A5T		50		0.001	4	0.16
A1T		100	1985	0.001	4	0.16
A7T		75		0.001	4	0.16
A5T		50		0.001	4	0.16
A1T		100	1986	0.001	4	0.16
A7T		75		0.001	4	0.16
A5T		50		0.001	4	0.16
A1T		100	1987	0.001	4	0.16
A7T		75		0.001	4	0.16
A5T		50		0.001	4	0.16
A1T		100	1988	0.001	4	0.16
A7T		75		0.001	4	0.16
A5T		50		0.002	4	0.16

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-10
ISCST3 Model Predicted Maximum Annual Concentrations
of PM/PM_{10} at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
A1T	Annual	100	1984	0.0004	4	0.16
A7T		75		0.0004	4	0.16
A5T		50		0.0005	4	0.16
A1T		100	1985	0.0003	4	0.16
A7T		75		0.0004	4	0.16
A5T		50		0.0004	4	0.16
A1T		100	1986	0.0004	4	0.16
A7T		75		0.0005	4	0.16
A5T		50		0.0005	4	0.16
A1T		100	1987	0.0003	4	0.16
A7T		75		0.0003	4	0.16
A5T		50		0.0004	4	0.16
A1T		100	1988	0.0003	4	0.16
A7T		75		0.0004	4	0.16
A5T		50		0.0004	4	0.16

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-11
ISCST3 Model Predicted Maximum 24-Hour Concentrations
of PM/PM_{10} at Okefenokee

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
SNG1	24-Hour	100	1984	0.04	8	0.32
SNG7		75		0.04	8	0.32
SNG5		50		0.05	8	0.32
SNG1		100	1985	0.02	8	0.32
SNG7		75		0.03	8	0.32
SNG5		50		0.03	8	0.32
SNG1		100	1986	0.03	8	0.32
SNG7		75		0.03	8	0.32
SNG5		50		0.04	8	0.32
SNG1		100	1987	0.03	8	0.32
SNG7		75		0.03	8	0.32
SNG5		50		0.04	8	0.32
SNG1		100	1988	0.04	8	0.32
SNG7		75		0.04	8	0.32
SNG5		50		0.05	8	0.32
SFO1	24-Hour	100	1984	0.07	8	0.32
SFO7		75		0.08	8	0.32
SFO5		50		0.08	8	0.32
SFO1		100	1985	0.05	8	0.32
SFO7		75		0.05	8	0.32
SFO5		50		0.06	8	0.32
SFO1		100	1986	0.06	8	0.32
SFO7		75		0.06	8	0.32
SFO5		50		0.07	8	0.32
SFO1		100	1987	0.06	8	0.32
SFO7		75		0.06	8	0.32
SFO5		50		0.07	8	0.32
SFO1		100	1988	0.06	8	0.32
SFO7		75		0.07	8	0.32
SFO5		50		0.09	8	0.32

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-12
ISCST3 Model Predicted Maximum 24-Hour Concentrations
of PM/PM_{10} at Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	Class I SIL* ($\mu g/m^3$)
SNG1	24-Hour	100	1984	0.02	8	0.32
SNG7		75		0.02	8	0.32
SNG5		50		0.02	8	0.32
SNG1		100	1985	0.01	8	0.32
SNG7		75		0.01	8	0.32
SNG5		50		0.01	8	0.32
SNG1		100	1986	0.01	8	0.32
SNG7		75		0.01	8	0.32
SNG5		50		0.01	8	0.32
SNG1		100	1987	0.01	8	0.32
SNG7		75		0.01	8	0.32
SNG5		50		0.02	8	0.32
SNG1		100	1988	0.01	8	0.32
SNG7		75		0.01	8	0.32
SNG5		50		0.01	8	0.32
SFO1	24-Hour	100	1984	0.04	8	0.32
SFO7		75		0.04	8	0.32
SFO5		50		0.04	8	0.32
SFO1		100	1985	0.02	8	0.32
SFO7		75		0.02	8	0.32
SFO5		50		0.02	8	0.32
SFO1		100	1986	0.02	8	0.32
SFO7		75		0.02	8	0.32
SFO5		50		0.02	8	0.32
SFO1		100	1987	0.02	8	0.32
SFO7		75		0.02	8	0.32
SFO5		50		0.03	8	0.32
SFO1		100	1988	0.02	8	0.32
SFO7		75		0.02	8	0.32
SFO5		50		0.02	8	0.32

*Calculated as 4 percent of the PSD Class I Increment.

Table 5-13
Comparison of Maximum Predicted Impacts
with the PSD Class I Significant Impact Levels

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	PSD Class I Significant Impact Level
Okefenokee			
NO_x	Annual	0.010	0.1
SO_2	Annual	0.002	0.08
	3-Hour	**1.980**	1
	24-Hour	**0.420**	0.2
PM/PM_{10}	Annual	0.002	0.16
	24-Hour	0.090	0.32
Wolf Island			
NO_x	Annual	0.005	0.1
SO_2	Annual	0.001	0.08
	3-Hour	0.860	1
	24-Hour	**0.220**	0.2
PM/PM_{10}	Annual	0.001	0.16
	24-Hour	0.040	0.32

concentrations of NO_x and PM/PM_{10} are less than the applicable Class I SILs for the annual and 24-hour averaging periods, respectively, for both Class I areas. Likewise, SO_2 is also less than the applicable Class I SILs for the annual averaging period. However, SO_2 exceeds the 24-hour Class I SIL Okefenokee and the 3-hour Class I SIL for both Okefenokee and Wolf Island. A PSD increment analysis for SO_2 is warranted to show compliance.

5.3.2 PSD Class I Increment Analysis

A PSD Class I increment analysis was performed for SO_2 for 24-hour period at Okefenokee and the 3-hour period for both Okefenokee and Wolf Island Class I areas for the applicable years, fuel, and operating load since the ISC3 model predicted concentrations of SO_2 were greater than the applicable PSD Class I significant impact level.

The PSD increment is the maximum allowable increase in concentration that is allowed to occur in air quality levels at the time the baseline is set for a given pollutant. The baseline concentration, in general, is the ambient concentration existing at the time the first complete PSD permit application affecting the area is submitted.

Because Okefenokee is on the Florida state line and Wolf Island is in Georgia, FDEP was contacted regarding how to proceed with compiling the interactive source inventories from both states. Mr. Cleve Holladay at FDEP provided all PSD SO_2 increment consuming sources to be used for the analysis for both Class I areas. In addition, Mr. Holladay stated FDEP does not require a NAAQS analysis in addition to an increment analysis. The interactive for SO_2 source inventory received from FDEP on March 15, 1999 has been included as Attachment 6. As shown in Attachment 6, the interactive source inventory from FDEP contains PSD increment consuming and increment expanding sources.

The increment consuming and expanding sources provided by FDEP from the aforementioned inventory were included in the ISC3 air dispersion modeling analysis to determine the cumulative impact of these sources and the Project at each class I area for the applicable periods and loads. The model, receptor grids, meteorological data, and model options used in the previously performed modeling were also used in the multi-source interactive modeling analysis.

Table 5-14 presents the highest model predicted impacts for SO_2 for the 24-hour period at Okefenokee and the 3-hour period for both Okefenokee and Wolf Island Class I areas, with the maximum concentrations underlined. Furthermore, Table 5-14 summarizes the increment analysis by comparing the cumulative maximum predicted concentrations from

Table 5-14
ISCST3 Model Predicted Maximum Concentrations of SO_2 at for
the Applicable Averaging Periods and Loads at Okefenokee and Wolf Island

ISCST3 Operating Scenario	Averaging Period	Load	Year	Maximum Predicted Conc. (μg/m^3)	Class I Increment (μg/m^3)
			Okefenokee		
SFO1	3-Hour	100	1984	16.51	25
SFO7		75		16.51	25
SFO1		100	1985	11.82	25
SFO7		75		11.82	25
SFO5		50		11.82	25
SFO1		100	1986	9.53	25
SFO7		75		9.53	25
SFO1		100	1987	10.50	25
SFO7		75		10.50	25
SFO1		100	1988	11.23	25
SFO7		75		11.23	25
SFO5		50		11.23	25
SFO1	24-Hour	100	1984	2.87	5
SFO7		75		2.87	5
SFO5		50		2.87	5
SFO1		100	1985	2.21	5
SFO7		75		2.21	5
SFO5		50		2.21	5
SFO1		100	1986	1.64	5
SFO7		75		1.64	5
SFO5		50		1.64	5
SFO1		100	1987	1.84	5
SFO7		75		1.84	5
SFO5		50		1.84	5
SFO1		100	1988	1.18	5
SFO7		75		1.16	5
SFO5		50		1.14	5
			Wolf Island		
SFO1	24-Hour	100	1984	1.14	5
SFO7		70		1.14	5

the PSD interactive sources and the Project with the PSD Class I increments.

As the results indicate, the predicted concentrations are less than the applicable PSD Class I increments (i.e., the Project's ambient air quality impacts, including ambient air quality impacts from nearby increment consuming sources which impact the Project's impact area, do not exceed the PSD Class I increments).

5.4 Visibility/Regional Haze Analysis

The additional impact analysis requirements of a PSD permit application are concerned with visibility impairment within the proposed project's impact area. The general components of a visibility impairment analysis include:

- Determine the visual quality of the area.
- Determine the potential for visibility impairment with a screening level assessment.
- If warranted, conduct a more in-depth analysis of the visibility impairment potential.

5.4.1 Visual Quality of the Area

The Project is located in northeastern Florida, immediately surrounded by forest and grassland. The climate is characterized as nearly tropical with warm temperatures and abundant moisture. The high relative humidity and coastal influence generally result in moderate visibility with relatively low background visual ranges.

5.4.2 Visual Impairment Screening Assessment

A visibility impairment screening analysis was conducted in accordance with EPA's Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015, September 1988, hereinafter referred to as the Workbook), and guidance contained in the EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility (EPA-454/R-93-05, hereinafter referred to as IWAQM), April 1993, for the Class I Area located less than 50 km from the Project in order to provide a conservative indication of the perceptibility of plumes from the proposed emission source. The only Federal PSD Class I Area within 50 km is the Okefenokee Wilderness Area located approximately 34 km northwest of the Project. It should be noted, a regional haze analysis was conducted for Class I areas located at a distances greater than 50 km (see Section 5.4.2).

The analysis was performed using the VISCREEN model. In accordance with Workbook visual screening procedures and the IWAQM guidance, the VISCREEN plume visual impact screening model was used with default worst-case Level-1 visual screening parameters using the maximum estimated emission rates of NO_x and PM/PM_{10} as presented in Table 2-1.

In accordance with EPA procedures, the plume visual impact screening model (VISCREEN) was utilized with input and default parameters appropriately chosen for this geographical region. The criteria for evaluating whether there is significant visibility impairment is whether the plume from a source has the potential to be perceptible to untrained observers under reasonable worst-case conditions. The majority of input parameter values were not changed from the VISCREEN default values as specified in the Workbook. However, background visual range, stability class, and windspeed parameters have been changed to values more representative of the specific region and operating conditions of the Project, therefore producing a more realistic analysis. The situation-specific modeled values are described below:

Emissions. Table 2-1 shows the worst-case maximum hourly emissions of Nitrogen Oxide (NO_x) and Particulate Matter (PM/PM_{10}) used in the visibility analysis modeling. The worst-case maximum hourly emissions include those from the SCCTs and the diesel fire pump for each of the Project's operating scenarios.

Distances. The geometry of the Project and the Okefenokee Wilderness Area make the source-observer and minimum source distance 34 km and the maximum source distance 80 km.

Background Visual Range. A background visual range value which is considered representative of the area was based on a telephone conversation with Mr. Bud Rolofson at the Fish and Wildlife Service in Denver, Colorado on January 15, 1999. The background visual range is 65 km.

Stability Class and Windspeed. The VISCREEN stability class default value of 'F' and windspeed default value of 1.0 meter per second (m/s) were found not to be representative of the general climatological conditions of the area in the vicinity of the Project. Therefore, stability class information contained in the five years (1984-1988) of meteorological data that were used in Section 4.2 were analyzed to determine a more representative stability class. A frequency distribution for Stability Classes 1 through 7 was performed for each season of each of the five years of meteorological data. The results of the analysis show that 'D' Class stability, or neutral stability, is most common stability class contained within the five years of meteorological data. See Attachment 7 for the results of the frequency distribution.

To establish a more representative wind speed, climatological data were reviewed for this area. Windspeed values of 7.9 miles per hour (mph) (3.53 m/s) were given in the Local Climatological Data Annual Summaries for 1996, Part IV - Southern Region published by the National Oceanic and Atmospheric Administration (NOAA) for Jacksonville, Florida. This windspeed value was determined to be more representative of the windspeeds in the Project area than the VISCREEN default value of 1.0 m/s.

The VISCREEN results are provided in Attachment 7. Based on the results of this analysis the Project plume visual impact passes the Level-2 analysis specified by the Workbook for a CLASS I area. Potential visual impairment from the Project plume will not cause a notable problem or be perceptible to untrained observers. However, under certain short-term wind, meteorological, visual backgrounds, and sun angle conditions in the vicinity of the Project a plume may be detected.

The report output of the VISCREEN model is included in Attachment 7. Results of the Level-1 visual screening analysis indicate that the conservative screening criteria are not exceeded. Therefore, further analyses to quantify the extent of any reductions in visibility due to emissions from the Project are not warranted based on the results of the Level-1 visual impairment screening analysis.

5.4.3 Regional Haze Analysis

A regional haze analysis was performed in accordance with guidance published in the IWAQM document, as well as technical guidance and an example provided by the NPS to evaluate the potential for visibility impairment (significant increase in uniform haze) at the Wolf Island Wilderness area. The Okefenokee Wilderness Area was not assessed because its closest boundary is less than 50 km from the project as described in the IWAQM document. Visibility impairment occurs as a result of the scattering and absorption of light due to particles and gasses in the atmosphere. On a local-scale, visual impairment is generally defined as a plume or layered haze from a single source or small group of sources. This phenomena, known as regional haze, impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. The methodology, input, and results are described in the following subsections.

5.4.3.1 Analysis Methodology and Input. The reduction of image forming light per unit distance in the atmosphere due to the sum of scattering (light redirected away from the sight path) and adsorption (light captured by aerosols and turned into heat energy) is represented by a term known as the extinction coefficient (b_{ext}). Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level (usually set at 2% difference between target and sky), a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere. With the aforementioned assumptions, extinction can be related to visual range with the following equation:

$$b_{ext} = \frac{3.912}{vr}$$

Where: b_{ext} = extinction coefficient, 1/km
vr = visual range, km

A uniform incremental change in b_{ext} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a change in b_{ext}, or; percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, the Level I screening analysis is satisfied, and no further analysis is required. The percent change in extinction is calculated as follows:
Where: b_{exts} = source extinction coefficient

$$= \frac{b_{exts}}{b_{extb}}(100\%)$$

b_{extb} = background extinction coefficient

The source extinction coefficient is calculated as a function of the source's NO_x and fine PM model predicted concentration levels at the Class I area, as well as the ambient relative humidity. Although relative humidity does not by itself cause visibility to be degraded, some particles in the atmosphere accumulate water and grow to just the right size to be very efficient at scattering light. Based on guidance from the IWAQM document and NPS, the source extinction coefficient may be calculated as follows:

$$b_{exts} = (0.003)(RH_f)[(NH_4)_2SO_4 + NH_4NO_3] + (0.003)(PM_{fine})$$

Where: RH_f = relative humidity correction factor to adjust for the effects of ambient humidity on light extinction calculations.

NH_4NO_3 = concentration of ammonium nitrate in units of $\mu g/m^3$, calculated as (NO_x 24-h concentration, $\mu g/m^3$)(1.35)(1.29), assuming all NO_x converts to ammonium nitrate.

$(NH_4)_2SO_4$= concentration of ammonium sulfate in units of $\mu g/m^3$, calculated as (SO_2 24-h concentration, $\mu g/m^3$)(1.5)(1.375), assuming all SO_2 converts to ammonium sulfate.

PM_{fine}= concentration of primary fine particulate in units of $\mu g/m^3$, calculated as (PM/PM_{10} 24-h concentration, $\mu g/m^3$)(1.0), assuming all PM/PM_{10} is primary fine particulate.

The background extinction coefficient is calculated as a function of the estimated visual range as follows:

$$b_{extb} = \frac{3.912}{vr}$$

Where: b_{extb} = background extinction coefficient, 1/km

vr = background visual range, km

5.4.3.2 Regional Haze Calculations and Results. Based on the aforementioned methodology, the percent change in extinction for normal SCCT operation and 5 years of meteorological data was assessed in the refined modeling analysis presented in Section 4.0. The results of the analysis are presented in a spreadsheet included as Attachment 8. The ISCST3 air dispersion model was used in the flat terrain mode to determine the maximum predicted 24-hour impacts of NO_x, SO_2, and PM/PM_{10} at a receptor placed at the closest boundary point of the Wilderness Area. Actual relative humidity data corresponding to the date of the maximum predicted NO_x and SO_2 impacts for each scenario were used in the regional haze calculations.

As the results in Attachment 8 indicate, the maximum percent change in extinction for all five years of 3 percent is less than screening threshold for Level I analyses of 5 percent. Therefore, further analysis of potential visibility impairment is not warranted.

Attachments

Attachment 1
(Turbine Vendor Data)

JEA - Inlet Bleet Heat

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	173,200.	129,900.	86,600.	43,300.	182,000.	136,500.	91,000.	45,500.
Heat Rate (LHV)	Btu/kWh	9,370.	10,120.	12,190.	16,820.	10,010.	10,830.	12,780.	17,070.
Heat Cons. (LHV) X 10^6	Btu/h	1,622.9	1,314.6	1,055.7	728.3	1,821.8	1,478.3	1,163.	776.7
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	172,590.	129,290.	85,990.	42,690.	180,460.	134,960.	89,460.	43,960.
Heat Rate (LHV) Net	Btu/kWh	9,400.	10,170.	12,280.	17,060.	10,100.	10,950.	13,000.	17,670.
Exhaust Flow X 10^3	lb/h	3542.	2890.	2397.	2182.	3683.	2827.	2406.	2215.
Exhaust Temp.	Deg F.	1116.	1139.	1184.	1013.	1098.	1194.	1200.	1013.
Exhaust Heat (LHV) X 10^6	Btu/h	973.0	823.2	720.4	551.1	1011.7	865.3	744.8	562.1
Water Flow	lb/h	0.	0.	0.	0.	119,700.	90,620.	61,970.	27,170.

EMISSIONS

NOx	ppmvd @ 15% O2	15.	15.	15.	77.	42.	42.	42.	42.
NOx AS NO2	lb/h	99.	79.	63.	220.	318.	256.	199.	131.
CO	ppmvd	15.	15.	15.	65.	20.	20.	30.	254.
CO	lb/h	48.	39.	33.	131.	65.	50.	63.	514.
UHC	ppmvw	7.	7.	7.	30.	7.	7.	7.	23.
UHC	lb/h	14.	11.	9.	36.	15.	11.	9.	28.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.90	0.90	0.90	0.86	0.84	0.86	0.90
Nitrogen	74.39	74.44	74.55	75.23	71.30	71.26	72.20	74.38
Oxygen	12.38	12.51	12.85	14.80	11.09	10.69	11.62	14.35
Carbon Dioxide	3.90	3.84	3.69	2.78	5.48	5.75	5.28	3.83
Water	8.44	8.32	8.02	6.29	11.28	11.46	10.04	6.55

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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JEA - Inlet Bleed Heat

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	20.	20.	20.	20.	20.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	186,500.	139,900.	93,300.	46,600.	192,700.	144,500.	96,400.	48,200.
Heat Rate (LHV)	Btu/kWh	9,310.	9,950.	11,910.	16,280.	10,040.	10,840.	12,680.	16,690.
Heat Cons. (LHV) X 10^6	Btu/h	1,736.3	1,392.	1,111.2	758.6	1,934.7	1,566.4	1,222.4	804.5
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	185,890.	139,290.	92,690.	45,990.	191,160.	142,960.	94,860.	46,660.
Heat Rate (LHV) Net	Btu/kWh	9,340.	9,990.	11,990.	16,500.	10,120.	10,960.	12,890.	17,240.
Exhaust Flow X 10^3	lb/h	3801.	3025.	2486.	2297.	3914.	2925.	2439.	2332.
Exhaust Temp.	Deg F.	1081.	1112.	1160.	966.	1068.	1183.	1200.	962.
Exhaust Heat (LHV) X 10^6	Btu/h	1036.9	863.8	751.3	569.2	1074.8	913.4	777.8	578.7
Water Flow	lb/h	0.	0.	0.	0.	130,530.	100,950.	68,710.	28,730.

EMISSIONS

NOx	ppmvd @ 15% O2	15.	15.	15.	80.	42.	42.	42.	42.
NOx AS NO2	lb/h	106.	84.	66.	238.	338.	271.	209.	136.
CO	ppmvd	15.	15.	15.	104.	20.	20.	26.	282.
CO	lb/h	52.	41.	34.	221.	69.	51.	57.	605.
UHC	ppmvw	7.	7.	7.	47.	7.	7.	7.	27.
UHC	lb/h	15.	12.	10.	60.	15.	12.	10.	35.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.91	0.89	0.89	0.90	0.86	0.84	0.86	0.91
Nitrogen	74.99	75.00	75.11	75.86	71.77	71.48	72.40	74.99
Oxygen	12.54	12.57	12.88	15.00	11.20	10.54	11.39	14.59
Carbon Dioxide	3.90	3.89	3.75	2.77	5.49	5.89	5.48	3.78
Water	7.67	7.65	7.37	5.48	10.69	11.25	9.87	5.74

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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JEA - Inlet Bleed Heat

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%	BASE	75%	50%	25%
Ambient Temp.	Deg F.	95.	95.	95.	95.	95.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	20,675	20,675	20,675	20,675	18,550	18,550	18,550	18,550
Fuel Temperature	Deg F	60	60	60	60	60	60	60	60
Liquid Fuel H/C Ratio						1.9	1.9	1.9	1.9
Output	kW	150,500.	112,800.	75,200.	37,600.	160,100.	120,100.	80,100.	40,000.
Heat Rate (LHV)	Btu/kWh	9,760.	10,690.	12,940.	18,180.	10,240.	11,170.	13,270.	18,180.
Heat Cons. (LHV) X 10^6	Btu/h	1,468.9	1,205.8	973.1	683.6	1,639.4	1,341.5	1,062.9	727.2
Auxiliary Power	kW	608	608	608	608	1,542	1,542	1,542	1,542
Output Net	kW	149,890.	112,190.	74,590.	36,990.	158,560.	118,560.	78,560.	38,460.
Heat Rate (LHV) Net	Btu/kWh	9,800.	10,750.	13,050.	18,480.	10,340.	11,320.	13,530.	18,910.
Exhaust Flow X 10^3	lb/h	3254.	2691.	2265.	2064.	3365.	2693.	2318.	2089.
Exhaust Temp.	Deg F.	1144.	1170.	1200.	1043.	1133.	1200.	1200.	1053.
Exhaust Heat (LHV) X 10^6	Btu/h	901.9	776.4	679.4	527.2	936.0	810.4	701.1	540.4
Water Flow	lb/h	0.	0.	0.	0.	93,590.	69,010.	46,070.	19,720.

EMISSIONS

NOx	ppmvd @ 15% O2	15.	15.	15.	58.	42.	42.	42.	42.
NOx AS NO2	lb/h	89.	73.	58.	156.	286.	232.	182.	123.
CO	ppmvd	15.	15.	15.	61.	20.	20.	36.	254.
CO	lb/h	43.	36.	30.	115.	59.	47.	74.	480.
UHC	ppmvw	7.	7.	7.	28.	7.	7.	7.	21.
UHC	lb/h	13.	11.	9.	33.	13.	11.	9.	25.
Particulates	lb/h	9.	9.	9.	9.	17.	17.	17.	17.

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.86	0.86	0.87	0.84	0.84	0.85	0.86
Nitrogen	72.71	72.76	72.89	73.50	70.25	70.48	71.33	73.01
Oxygen	12.10	12.24	12.64	14.42	10.97	10.92	11.83	14.06
Carbon Dioxide	3.82	3.75	3.57	2.74	5.37	5.45	4.99	3.78
Water	10.51	10.39	10.04	8.47	12.57	12.31	11.01	8.29

SITE CONDITIONS

Elevation	ft.	27.0
Site Pressure	psia	14.69
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		15/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0 WT% Sulfur Content in the Fuel.

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Attachment 2
(Tanks Model Output)

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
TANK IDENTIFICATION AND PHYSICAL CHARACTERISTICS

Identification

Identification No.:	
City:	Brandy Branch
State:	FL
Company:	JEA - F.O. Storage Tanks
Type of Tank:	Vertical Fixed Roof
Description:	Fuel Oil Storage Tank

Tank Dimensions

Shell Height (ft):	40.0
Diameter (ft):	65.6
Liquid Height (ft):	39.8
Avg. Liquid Height (ft):	20.0
Volume (gallons):	1000000
Turnovers:	11.1
Net Throughput (gal/yr):	11100000

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft):	0.00
Radius (ft) (Dome Roof):	56.00
Slope (ft/ft) (Cone Roof):	0.0000

Breather Vent Settings

Vacuum Setting (psig):	-0.03
Pressure Setting (psig):	0.03

Meteorological Data Used in Emission Calculations: Jacksonville, Florida (Avg Atmospheric Pressure = 14.7 psia)

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	69.94	64.36	75.52	68.02	0.0089	0.0075	0.0107	130.000			188.00	Option 3: A=12.1010, B=8907.0

Annual Emission Calculations

Standing Losses (lb):	243.2499
Vapor Space Volume (cu ft):	86154.41
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.038277
Vented Vapor Saturation Factor:	0.988064
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	86154.41
Tank Diameter (ft):	65.6
Vapor Space Outage (ft):	25.49
Tank Shell Height (ft):	40.0
Average Liquid Height (ft):	20.0
Roof Outage (ft):	5.49
Roof Outage (Dome Roof)	
Roof Outage (ft):	5.49
Dome Radius (ft):	56
Shell Radius (ft):	32.8
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Daily Avg. Liquid Surface Temp.(deg. R):	529.61
Daily Average Ambient Temp. (deg. R):	527.67
Ideal Gas Constant R (psia cuft /(lb-mole-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	527.69
Tank Paint Solar Absorptance (Shell):	0.17
Tank Paint Solar Absorptance (Roof):	0.17
Daily Total Solar Insolation Factor (Btu/sqft□day):	1438.00

Vapor Space Expansion Factor

Vapor Space Expansion Factor:	0.038277
Daily Vapor Temperature Range (deg.R):	22.32
Daily Vapor Pressure Range (psia):	0.003180
Breather Vent Press. Setting Range(psia):	0.06
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.007476
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.010655
Daily Avg. Liquid Surface Temp. (deg R):	529.61
Daily Min. Liquid Surface Temp. (deg R):	524.03
Daily Max. Liquid Surface Temp. (deg R):	535.19
Daily Ambient Temp. Range (deg.R):	21.50

Annual Emission Calculations	
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.988064
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Vapor Space Outage (ft):	25.49
Working Losses (lb):	307.2093
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Annual Net Throughput (gal/yr):	11100000
Turnover Factor:	1.0000
Maximum Liquid Volume (cuft):	134518
Maximum Liquid Height (ft):	39.8
Tank Diameter (ft):	65.6
Working Loss Product Factor:	1.00
Total Losses (lb):	550.46

Annual Emissions Report

Liquid Contents	Losses (lbs.): Standing	Working	Total
Distillate fuel oil no. 2	243.25	307.21	550.46
Total:	243.25	307.21	550.46

□

Attachment 3

(Emission Calculation Spreadsheet)

JEA 60903.0030
Jacksonville, Florida
Enveloped Stack Parameters

4000 Hours of natural gas simple cycle operation per year
800 Hous of fuel oil simple cycle operation per year

Last Revised 03/05/99
Date Printed 03/22/99 02:11 PM

	NATURAL GAS OPERATION			SHORT TERM		ANNUALIZED (d)		FUEL OIL OPERATION			SHORT TERM		ANNUALIZED (d)		Total Annual Dual Fuel Parameters (e)	
Load	100 Percent							100 Percent								
Turbine	PG7241 (FA)			Representative*		59 Degrees		PG7241 (FA)			Representative*		59 Degrees			
Ambient Temperature (F)	95	59	[illegible]	100 Pecent Load		100 Pecent Load		95	59	20	100 Pecent Load		100 Pecent Load		100 Pecent Load	
Exit Velocity (ft/s)	147.76	156.75	164.0	147.76 ft/s	45.04 m/s	156.75 ft/s	47.78 ft/s	151.8	161.6	168.04	151.8 ft/s	46.27 m/s	161.60 ft/s	49.26 m/s	156.75 ft/s	47.78 m/s
Exit Temp (F)	1144	1116	1081	1081 F	855.93 K	1116.00 F	875.37 K	1133	1098	1068	1068 F	848.71 K	1098.00 F	865.37 K	1116.00 F	875.37 K
Emissions (lb/h)																
NOx (f)	71.20	79.20	84.80	84.8 lb/h	10.68 g/s	36.16 lb/h	4.56 g/s	286.00	318.00	338.00	338 lb/h	42.59 g/s	29.04 lb/h	3.66 g/s	65.21 lb/h	8.22 g/s
CO	43.00	48.00	52.00	52 lb/h	6.55 g/s	21.92 lb/h	2.76 g/s	59.00	65.00	69.00	69 lb/h	8.69 g/s	5.94 lb/h	0.75 g/s	27.85 lb/h	3.51 g/s
SO2 (a)	0.97	1.07	1.14	1.14 lb/h	0.14 g/s	0.49 lb/h	0.06 g/s	88.38	98.21	104.30	104.3 lb/h	13.14 g/s	8.97 lb/h	1.13 g/s	9.48 lb/h	1.19 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.86 lb/h	0.71 g/s
VOC (c)	2.60	2.80	3.00	3 lb/h	0.38 g/s	1.28 lb/h	0.18 g/s	2.60	3.00	3.00	3 lb/h	0.38 g/s	0.27 lb/h	0.03 g/s	1.55 lb/h	0.20 g/s

Load	75 Percent							75 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees		PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	75 Pecent Load		75 Pecent Load		95	59	20	75 Pecent Load		75 Pecent Load		75 Pecent Load	
Exit Velocity (ft/s)	124.17	129.71	133.13	124.17 ft/s	37.85 m/s	129.71 ft/s	39.54 m/s	126.43	131.67	135.15	126.43 ft/s	38.54 m/s	131.67 ft/s	40.13 m/s	129.71 ft/s	39.54 m/s
Exit Temp (F)	1170	1139	1112	1112 F	873.15 K	1139.00 F	888.15 K	1200	1194	1183	1183 F	912.59 K	1194.00 F	918.71 K	1139.00 F	888.15 K
Emissions (lb/h)																
NOx (f)	58.40	63.20	67.20	67.2 lb/h	8.47 g/s	28.86 lb/h	3.64 g/s	232.00	256.00	271.00	271 lb/h	34.14 g/s	23.38 lb/h	2.95 g/s	52.24 lb/h	6.58 g/s
CO	36.00	39.00	41.00	41 lb/h	5.17 g/s	17.81 lb/h	2.24 g/s	47.00	50.00	51.00	51 lb/h	6.43 g/s	4.57 lb/h	0.58 g/s	22.37 lb/h	2.82 g/s
SO2 (a)	0.79	0.86	0.92	0.92 lb/h	0.12 g/s	0.39 lb/h	0.05 g/s	72.32	79.69	84.44	84.44 lb/h	10.64 g/s	7.28 lb/h	0.92 g/s	7.67 lb/h	0.97 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.20	2.2	2.4	2.4 lb/h	0.30 g/s	1.00 lb/h	0.13 g/s	2.20	2.2	2.4	2.4 lb/h	0.30 g/s	0.20 lb/h	0.03 g/s	1.21 lb/h	0.15 g/s

Load	50 Percent							50 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees		PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	50 Pecent Load		50 Pecent Load		95	59	20	50 Pecent Load		50 Pecent Load		50 Pecent Load	
Exit Velocity (ft/s)	106.35	110.53	112.68	106.35 ft/s	32.42 m/s	110.53 ft/s	33.69 m/s	108.45	112.04	113.42	108.45 ft/s	33.06 m/s	112.04 ft/s	34.15 m/s	110.53 ft/s	33.69 m/s
Exit Temp (F)	1200	1184	1160	1160 F	899.82 K	1184.00 F	913.15 K	1200	1200	1200	1200 F	922.04 K	1200.00 F	922.04 K	1184.00 F	913.15 K
Emissions (lb/h)																
NOx (f)	46.40	50.40	52.80	52.8 lb/h	6.65 g/s	23.01 lb/h	2.90 g/s	182.00	199.00	209.00	209 lb/h	26.33 g/s	18.17 lb/h	2.29 g/s	41.19 lb/h	5.19 g/s
CO	30.00	33.00	34.00	34 lb/h	4.26 g/s	15.07 lb/h	1.90 g/s	74.00	63.00	57.00	74 lb/h	9.32 g/s	5.75 lb/h	0.72 g/s	20.82 lb/h	2.62 g/s
SO2 (a)	0.64	0.69	0.73	0.73 lb/h	0.09 g/s	0.32 lb/h	0.04 g/s	57.30	62.70	65.90	65.9 lb/h	8.30 g/s	5.73 lb/h	0.72 g/s	6.04 lb/h	0.76 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.62 lb/h	0.10 g/s	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.18 lb/h	0.02 g/s	0.99 lb/h	0.12 g/s

NOTE:

(a) SO2 values were calculated based on 0.2 gr/100 scf in the natural gas and #2 distillate fuel oil (0.05% sulfur)
Example Calculations:
Natural gas 100 percent load at 95F = (1,468.9 MBtu/hr)*(lb/23.8 ft^3)*(20,675 Btu/lb)*(0.2gr/100scf)*(1lb/7000gr)*(64SO2/32S)*(10^6Btu/MBtu) = 0.97 lb/hr.
#2 Dist. Fuel Oil 100 percent load @ 95F = (0.05lb S/100lb fuel)*(64 lb SO2/32 lb S)*(7.05 lb fuel/1gal)*(1gal/7.05 lb)*(lb/ 18,550 Btu)*(1,639.4 MBtu/hr)*(10^6 BTU/MBtu) = 88.38 lb/hr.
(b) PM emission values are for front half filterable emissions only.
(c) VOC emissions represent 20% of the UHC emissions.
(d) Annualized emission rate based on specific number of hours of Natural Gas and Fuel Oil operation.
(e) Exit Velocity and Exit Temperature values are from the annualized natural gas operating scenarios.
The emission rate values are annualized @ 59 F based on the number of hour of fuel specific firing.
(f) NOx emission values for natural gas firing are at 12 ppm and 42 ppm for fuel oil firing.

Annual Potential to Emit Calculations (59 F)

Pollutant	Maximum Emission Rates Natural Gas SCCT (lb/hr)	Maximum Emission Rates Fuel Oil SCCT (lb/hr)	Fire Pump (lb/hr)	Single SCCT (tpy)	Fire Pump (tpy)	Facility Total (tpy)	PSD SEL (tpy)	Exceed SEL (yes/no)	
NOx	79.2	318	11.7	285.6	0.304	857.7	40	yes	NOx
CO	48	65	2.5	122.0	0.065	366.2	100	yes	CO
SO2	1.07	98.21	0.8	41.4	0.021	124.3	40	yes	SO2
VOC	2.8	3	0.9	6.8	0.023	20.5	40	no	VOC
PM/PM10	9	17	0.8	24.8	0.021	74.5	15	yes	PM/PM10
H2SO4	0.13	11.98	0.1	5.1	0.003	15.2	7	yes	H2SO4
Total Reduced Sulfur (TRS)	negl.					negl.	10	no	TRS
Hydrgen Sulfide (H2S)	negl.					negl.	10	no	H2SO4
Vinyl Chlorides (VC)	negl.					negl.	1	no	VC
Total Flourides (TF)	negl.					negl.	3	no	TF
Arsenic (As)	negl.	8.93E-03				negl.		no	As
Mercury (Hg)	negl.	1.66E-03				negl.	0.1	no	Hg
Beryllium (Be)	negl.	6.01E-04				negl.	0.0004	no	Be
Lead (Pb)	negl.	0.106				0.042	0.6	no	Pb

3 # of turbines
4000 hours of natural gas simple cycle operation per year
800 hours of fuel oil simple cycle operation per year
52 hours of diesel fire pump operation per year

Notes:

a Worst Case emissions are from 100, 75, and 50% loads for one vendor at 59 F.
b SO2 emissions are based on 0.2 gr/100 scf sulfur in the natural gas for the simple cycle turbines and #2 distillate fuel oil (0.05% sulfur) for the fuel oil simple cycle turbines.
c H2SO4 based on a 10% conversion of SO2 to SO3 and a molecular ratio of 1.22 from SO3 to H2SO4.
d Trace element emission rates were calculated using AP-42 emission factors (Table 3.1-4) and a worst case heat input between 100, 75, and 50% loads @ 59F (NG=1,622.9 MBtu/hr & FO=1,821.8.0 MBtu/hr).
e VOC emissions represent 20% of the UHC emissions from 100, 75, and 50% loads for one vendor at 59 F.
f Diesel fire pump emissions were calculated using AP-42 emission factors (Table 3.3-1) and were based on an assumed diesel fire pump size of 125 BHP (~379 hp assuming 33% efficiency).
g PM/PM10 emissions are for front half only.
h NOx emissions are based on 12 ppm for natural gas and 42 ppm for fuel oil.

i AP-42 Emission Factors (oil)

As	4.90E-06	lb/MBtu
Hg	9.10E-07	lb/MBtu
Be	3.30E-07	lb/MBtu
Pb	5.80E-05	lb/MBtu

Attachment 4
(Best Available Control Technology)

Best Available Control Technology Analysis

The Brandy Branch Project

Prepared for: Jacksonville Electric Authority

Prepared by: Black & Veatch

Executive Summary

A BACT analysis was performed for three (3) new General Electric 7FA combustion turbines to be installed at the Brandy Branch Project. The combustion turbines are to be operated as simple cycle combustion turbines (SCCT), i.e. without heat recovery steam generators, to allow faster response time to changing load demands. The following was evaluated to be BACT for the following emissions parameters for each SCCT.

Nitrogen oxides (NO_x) emissions -- BACT was determined to be the use of dry low NO_x burners during natural gas firing and water injection for fuel oil firing to achieve the following emission limits.

- Burning natural gas at unit loads between 50 percent and 100 percent of normal capacity, an emission limit of 12 ppmvd (referenced to 15 percent O_2).
- Burning fuel oil at load between 50 and 100 percent of normal capacity, an emission limit of 42 ppmvd (referenced to 15 percent O_2).

Carbon monoxide (CO) emissions--Good combustion controls to achieve a CO emission limit of 15 ppmvd during natural gas firing or 20 ppmvd during fuel oil firing.

Particulate emissions--Good combustion controls.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)--Good combustion controls using natural gas and fuel oil with less than 0.5 percent sulfur.

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List of Tables

1.0 Introduction

The 1977 Clean Air Act established revised conditions for the approval of pre-construction permit applications under the Prevention of Significant Deterioration (PSD) program. One of these requirements is that the best available control technology (BACT) be installed for all pollutants regulated under the act emitted in significant amounts from new major sources or modifications. The new major sources proposed for this project include three combustion turbines and a diesel generator that are subject to the BACT rules. This document presents the BACT analysis and results for the new major sources on this project.

2.0 BACT Analyis Basis

This section describes the basis of this BACT analysis. Information is provided on such issues as the project description, BACT methodology and approach used, and the parameters and factors used in developing the analysis are identified.

2.1 Project Description

The Brandy Branch Project will consist of the installation of three General Electric 7FA combustion turbine electric generating units. Each combustion turbine unit will consist of one turbine and one generator operating as simple cycle combustion turbines (SCCT). The output rating for each of the new units will be nominally 172.6 MW net while firing gas. Total plant output will be nominally 517.8 MW.

The combustion turbines will fire natural gas as the primary fuel and No. 2 fuel oil as an emergency back-up fuel. The proposed operating scenario for the combustion turbines includes limiting the firing of natural gas to 12,000 hour per year for the facility (equivalent to a per unit operation of 4,000 hours per year) and limiting firing of No. 2 fuel oil to no more than 2,400 hours per year for the facility (equivalent to a per unit operation of 800 hours per year).

2.2 BACT Methodology

As defined in the air permit application, operation of the Project will result in an increase in the potential to emit emissions of NO_x, CO, PM/PM_{10}, and SO_2/Sulfuric Acid Mist (SAM); in excess of the major modification PSD threshold levels set for these pollutants. BACT is defined as an emission limitation established based on the maximum degree of pollutant reduction determined on a case-by-case basis considering technical, economic, energy, and environmental considerations. However, BACT cannot be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS).

To bring consistency to the BACT process, the United States Environmental Protection Agency (USEPA) has authorized the development of a guidance document (dated March 15, To bring consistency to the BACT process, the United States Environmental Protection Agency (USEPA) has authorized the development of a guidance document (dated March 15, 1990) on the use of the "top-down" approach to BACT determinations. The first step in a top-down BACT analysis is to determine, for the pollutant in question, the most stringent control technology and emission limit available for a similar source or source category. Technologies required under Lowest Achievable Emission Rate (LAER) determinations must be considered. These technologies represent the top control alternative under the BACT analysis. If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration.

Economic analysis used to determine the capital and annual costs of the control technologies were based on EPA methodologies shown in the EPA Best Available Control Technology Draft Guidance Document (October 1990), EPA BACT Guidelines, The Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (Fourth Edition), internal project developer cost factors, and vendor budgetary cost quotes.

2.3 Economic Basis

Table 2-1 lists the economic criteria used in the analysis of BACT alternatives.

Table 2-1
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	20
Real Interest Rate, percent	8.00
Economic Life years	20
Labor Cost, $/man-yr	60,000
Anhydrous Ammonia Cost, $/ton (1999)	230
Energy Cost, $/kWhr (1999)	.0221
Catalyst Life, years	3

3.0 BACT Analysis Basis

The BACT analysis for the SCCT units is based on certain regulatory requirements and project assumptions.

The following is a summary of the requirements and assumptions for which this BACT analysis is based:

- Federal and state ambient air quality standards, emission limitations, and other applicable regulations will be met.
- Federal NSPS for combustion turbines with heat input greater than 10 mmbtu/hr (40 CFR 60 Subpart GG) establish limiting criteria for SO_2 and NO_x emissions only. No NSPS criteria have been established for limiting CO, VOC, and PM/PM_{10} emissions. The following flue gas emission limits are established by NSPS for Subpart GG units:

  NO_x: 75 ppmvd at 15 percent O_2, corrected for fuel nitrogen content and turbine heat rate.
- The combustion turbine will have the following emission rates at 100 percent load:

	Natural gas	Fuel Oil
NO_x, ppmvd @ 15% O_2:	12	42
CO, ppmvd:	15	20
PM/PM_{10}, lb/mmbtu: (front half catch only)	0.0055	0.0093
SO_2, lb/hr	1.07	98.21

The proposed operating scenario for the combustion turbines includes limiting the firing of natural gas to 12,000 hour per year for the facility (equivalent to a per unit operation of 4,000 hours per year) and limiting firing of No. 2 fuel oil to no more than 2,400 hours per year for the facility (equivalent to a per unit operation of 800 hours per year).

4.0 NO_x BACT

The objective of this analysis is to determine BACT for NO_x emissions from the combustion turbines. Unless otherwise noted the NO_x emission rates described in this section are corrected to 15 percent oxygen.

4.1 BACT/LAER Clearinghouse Reviews

A review of the BACT/LAER Clearinghouse documents (CAPCOA, 1985-1992; USEPA, 1990 to present) indicates that the most stringent NO_x emissions limit for a natural gas fired CT is 3.0 ppmvd for the Sacramento Power Authority located in California. The emissions from that unit are controlled through the use of standard combustors and selective catalytic reduction (SCR). This unit is a combined cycle combustion turbine (CCCT) as compared to the simple cycle combustion turbine proposed for the Project. It should be noted that this combustion turbine is located in a non-attainment area for ozone, with NOx regulated as a non-attainment pollutant. Thus, this emission level represents LAER for CCCT.

For SCCT units, the strictest emission limit identified during the review is 5 ppm. This limit has been set for three different projects in California. These projects are the Southern California Gas Wheeler Ridge Gas plant located in the San Joaquin Valley, the Carson Energy Project in metropolitan Sacramento, and the Sacramento Power Authority Proctor and Gamble plant in metropolitan Sacramento. A summary of recent BACT/LAER determinations is provided in Appendix A.

It should also be noted that recently the South Coast Management District in California has officially declared new LAER limits for NO_x. This designation is limited to only specific application of CCCT projects and is not considered applicable to this Project as will be discussed.

Review of previous State of Florida DEP permits indicates that combustion turbine permits approved in the last 4 years have NO_x emission limits that vary from 15 to 9 ppmvd. The Oleander Power Project was recently granted a permit (Air Permit No. PSD-FL-258) during 1999 which limits NO_x emissions to 9 ppmvd when firing natural gas. Review of the permit conditions appear to indicate that fuel oil firing at 42 ppmvd will approach or equal the natural gas firing. The primary fuel proposed at Brandy Branch is natural gas.

4.2 Alternative NO_x Emission Reduction Systems

During combustion, NO_x is formed from two sources. Emissions formed through the oxidation of the fuel bound nitrogen are called fuel NO_x. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NOx and are a function of combustion temperature. NOx production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NOx-forming reactions. The overall average gas temperature required to drive the turbine is well below the flame temperature, but the flame region is required to achieve stable combustion.

Nitrogen oxides control methods may be divided into two categories: in-combustor NO_x formation control and post-combustion emission reduction. An in-combustor NO_x formation control process reduces the quantity of NOx formed in the combustion process. A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NOx emissions required. The different types of emission controls reviewed by this BACT analysis are as noted below.

In Combustor Type:

- Water/Steam Injection
- Dry Low NO_x Burners
- Xonon

Post Combustion Type:

- SNCR
- SCR
- SCONOX

4.2.1 Water or Steam Injection

NO_x emissions from the combustion turbines can be controlled by either water or steam injection. This type of control injects water or steam into the primary combustion zone with the fuel. The water or steam serves to reduce NO_x formation by reducing the peak flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water injected into the combustion turbine. Since the combustion turbine NSPS was last revised in 1982, manufacturers have improved combustion turbine tolerances to the water necessary to control NO_x emissions below the current NSPS level. However, there is a point at which the amount of water injected into the combustion turbine seriously degrades its reliability and operational life. This type of control can also be counterproductive with regard to carbon monoxide (CO) and volatile organic compound (VOC) emissions which are formed as a result of incomplete combustion.

The development of dry low-NO_x burners has replaced the use of wet controls except for certain cases such as oil firing. The use of water injection will be considered for operations when oil firing.

4.2.2 Dry Low NO_x Burners

NO_x can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of dry low NO_x (DLN) burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called dry low NO_x burners, because when firing fuel, no water needs to be injected into the combustion chamber to achieve low NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion systems as the state of the art for NO_x controls in combustion turbine.

DLN combustion turbine burner designs are available which uses improved air/fuel mixing and reduced flame temperatures to limit thermal NO_x formation. DLN burner technology uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. This two-stage process ensures good mixing of the air and fuel and minimizes the amount of air required, which results in low NO_x emissions. However, during fuel oil firing, dry low NO_x burners have not achieved emissions as low as with natural gas.

Also, as with the standard combustor with water injection, the dry low NO_x burners can also be counterproductive with regard to CO and VOC emissions. The staged combustion and lower combustion temperatures will result in higher CO and VOC emissions.

4.2.3 XONON

Another form of in-combustor control is Xonon. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2700 F at full power generation, which significantly reduces NOx emissions without raising and possibly even lowering emissions of carbon monoxide and unburned hydrocarbons. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce energy in the form of hot gases, which drive the turbine. This technology is being commercialized by several joint ventures that Catlaytica has with turbine manufacturers. To date, commercialization of this technology on utility size CTs such as proposed for the Project has not been developed.

4.2.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. However, the exhaust temperature at the exit of a combustion turbine, which ranges from 1,000 to over 1,200 for these CT units, is too low for any consideration of this technology. Temperatures in the range of 1,500-1,900 °F, along with adequate reaction time at this temperature range, are required to use this technology.

4.2.5 Selective Catalytic Reduction

Another post-combustion method is selective catalytic reduction (SCR). SCR systems have been used quite extensively in CCCT projects for the past 5 years. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed. The use of SCR results in small levels of ammonia emissions (ammonia slip). As the catalyst degrades ammonia slip will increase to approximately 10 ppm, ultimately requiring catalyst replacement.

The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas when it passes through the catalyst. Vanadia/titania catalysts have been used on the vast majority of SCR system installations (greater than 95 percent). The optimum flue gas temperature range for SCR operation using a conventional vanadia/titania catalyst is approximately 600 to 750 F. At temperatures above 800 F permanent damage to the vanadia/titania catalyst occurs. For the simple cycle turbines proposed for the Project, this temperature window does not exist. Flue gas from a SCCT will typically range from 1,050 F to 1,200 F. Accordingly, a vanadia/titania catalyst can not be installed at a simple cycle facility. Therefore, the vanadia/titania based catalyst will not be evaluated further for these units.

However, another catalyst material has been developed to which has had mixed success in limited application experiences. This catalyst uses zeolites, which can operate effectively at temperatures of up to 1,125 F, as the principle catalytic material. Zeolites, which are crystalline aluminasilicate compounds, do not contain materials classified as hazardous. Therefore, it is possible that these SCR catalysts can be disposed of by landfilling provided that contamination does not occur during SCR operation. Disposal would be subject to state and local regulations. Since zeolites have the most limited use of SCR catalysts, disposal requirements have not been adequately established. Zeolite based catalyst is significantly more expensive than the vanadia/titania based catalyst. In addition, the durability and effectiveness of zeolites in commercial SCR applications does not have a long history base.

Due to the high flue gas exit temperatures of the GE 7FA that can exceed 1200 F, the use of a zeolite catalyst would even require special precautions and equipment additions. As previously indicated, the maximum operating temperature of the catalyst is 1,125 F. To prevent damage to the catalyst at the higher temperatures a dilution air system and fan would need to be included for each unit to cool the flue gas to less than the maximum operating temperature of the catalyst. This analysis will include a dilution system in the evaluation of a zeolite SCR.

The operation of zeolite catalyst on sulfur bearing fuel fired units, such as oil fired units, also has very limited experience. In addition, the operation of a SCR on units that burn sulfur-bearing fuels will present a negative impact on the environmental performance of combustion turbine units. The environmental impact is due to the reaction of the excess ammonia that passes through the SCR with the sulfur trioxide (SO3) in the flue gas to form ammonia-sulfur salts, such as ammonium bisulfate. These compounds will form when the flue gas cools upon leaving the stack as a fine particulate that adds to the emissions of PM10 from the unit. This PM10 contributes to increased opacity from the unit, increased contribution to regional haze, and additional health risks. Previous regulating authorities have recognized these negative impacts and provided permit exemptions for operating the SCR during fuel oil firing.

This method of post-combustion control will be considered in this BACT analysis to control NO_x emissions when firing natural gas only.

4.2.6 SCONOX

A third, relatively new post-combustion technology is $SCONO_x$, which utilizes a coated oxidation catalyst to remove both NOx and CO. Based on this technology, the South Coast Management District recently declared LAER as 2.0 ppm of NO_x. However because the SCONOx catalyst is sensitive to SO2 concentrations and the catalyst is required to operate in temperature range between 550 F and 650 F, this technology is not applicable to the Project due to the simple cycle unit operation and fuel oil firing. This method of post-combustion control will not be considered in this BACT analysis.

4.2.7 Technology Summary

The following control technologies will be evaluated in this NO_x BACT analysis and are ranked in order of relative control effectiveness:

- The addition of zeolite catalyst SCR systems to reduce outlet emissions from each combustion turbine to 5.0 ppmvd during natural gas firing (LAER).
- In-combustor NO_x control consisting of dry low NO_x combustors to limit outlet emissions during natural gas firing to 12 ppmvd and water injection to limit outlet emissions to 42 ppmvd during fuel oil firing for all operating loads.

The NO_x emissions for a GE 7FA unit are summarized in Table 4-1.

4.3 Evaluation of Feasible Technologies

The following evaluation considers economic, energy, and environmental impacts for the potential BACT scenarios evaluated.

4.3.1 Economic Impacts

The use of SCR has significant economic impact to the Project. An analysis of the economic impact is provided in this section. The BACT costs presented in this analysis are based on operating the combustion turbine at full load for 4,000 hours per year on natural gas and 800 hours per year on No. 2 fuel oil.

4.3.1.1 Capital and Operating Costs.

Table 4-2 presents the capital costs for installing an SCR system on the General Electric 7FA combustion turbines to achieve a NO_x outlet emission level of 5.0 ppmvd (LAER) during natural gas firing. Consideration for design requirements for lowering the NO_x emission from 42.0 ppmvd during fuel oil firing were not included for the oil firing case due to its limited operating time, negative environmental impacts, and the uncertainty of its effectiveness while firing oil. The cost of the SCR system includes the ammonia receiving, storage, transfer,

Table 4-1
Estimated NO_x Emissions
From Alternate Control Technologies Per General Electric 7FA

Fuel	Control Technology Alternatives	
	Dry Low NO_x Combustors (Gas) - Water Injection (Oil)	SCR System
Natural Gas		
ppmvd (at 15% O_2)	12	5
Tons per year[a]	158.4	66
Fuel Oil		
ppmvd (at 15% O_2)	42	42
Tons per year[b]	127.2	127.2
BACT Analysis (Annual)[c]		
Tons per year	285.6	193.2

Notes:

[a] Annual emissions are based on 4,000 hours of operation per year at full load rating with an ambient temperature of 59 degree F..

[b] Annual emissions are based on 800 hours of operation per year at full load rating with an ambient temperature of 59 degree F.

[c] BACT analysis total emissions are based on 4,000 hours per year of natural gas firing and 800 hours per year of No. 2 fuel oil firing.

Table 4-2
NO_x Control Alternative Capital Cost Per General Electric 7FA

	SCR	Low NO_x Burners	Remarks
Direct Capital Cost			
Catalysts	1,556,000	NA	Scaled from previous projects
Catalyst Reactor	205,000	NA	Estimated
Control/Instrumentation	140,000	NA	Estimated
Dilution Air System	282,000	NA	Estimated for entire fan system
Ammonia Injection / Storage	290,000	NA	Scaled from previous projects
Balance of Plant	841,000	NA	For SCR: 8% Foundation & Supports, 10% Erection, 4% Electrical Installation, 1% Painting, 1% Insulation, 10% Engineering.
Total Direct Capital Cost	3,314,000	Base	
Indirect Capital Costs			
Contingency	663,000	NA	20% of Direct Capital Cost
Engineering and Supervision	331,000	NA	10% of Direct Capital Cost
Construction & Field Expense	166,000	NA	5% of Direct Capital Cost
Construction Fee	331,000	NA	10% of Direct Capital Cost,
Start-up Assistance	66,000	NA	2% of Direct Capital Cost
Performance Test	46,000	NA	Estimated Cost
Total Indirect Capital Costs	1,603,000	Base	
Total Installed Cost	4,916,000	Base	

Table 4-3

NO_x Control Alternative Annual Cost Per General Electric 7FA

	SCR	Low NO_x Burners	Remarks
Direct Annual Cost			Cost based on emissions in Table 4-1.
Catalyst Replacement	327,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	21,000	NA	See text for background information on this item
Reagent Feed	17,000	NA	Assumes 1.10 stoichiometric ratio
Power Consumption	30,000	NA	Includes dilution air fan
Lost Power Generation	34,000	NA	Back pressure on combustion turbine
Annual Distribution Check	17,000	NA	Required for SCR
Total Direct Annual Cost	446,000	NA	
Indirect Annual Costs			
Overhead	7,000	NA	60% of O&M Labor
Administrative Charges	98,000	NA	2% of Total Installed Cost
Property Taxes	135,000	NA	2.75% of Total Installed Cost
Insurance	49,000	NA	1% of Total Installed Cost
Capital Recovery	501,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	790,000	NA	
Total Annual Cost	**1,236,000**	NA	
Annual Emissions, tpy	193.2	285.6	Emissions taken from Table 4-1for oil firing
Emissions Reduction, tpy	92.4	NA	Emissions calculated from Table 4-1
Total Cost Effectiveness, $/ton	**13,380**	NA	Total Annual Cost/Emissions Reduction

vaporization, and injection; catalytic reactor; and balance of plant equipment. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates. Quotations for the catalyst material were based on zeolite catalysts.

Table 4-3 presents the annual operating costs and emission rates using SCR to achieve NO_x outlet emissions of 5.0 ppmvd while firing natural gas. Annual operating costs for SCR use include catalyst replacement, energy impacts, operating personnel, maintenance, reagent, and heat rate penalty. Throughout the life of the plant, catalyst elements will require periodic replacement. As the catalyst becomes deactivated, ammonia slip emissions will increase. At the point ammonia slip approaches 10 ppmvd the catalyst must be replaced. Currently, catalyst manufacturers are willing to guarantee a catalyst life of three years of equivalent operating hours) for the zeolite catalyst. The catalyst life is adjusted to account for the abbreviated operating hours each year of the peaking unit.

For conservatism in cost, ammonia consumption rates were based on a stoichiometric ratio of 1.10 for reacting NO. This higher stoichiometric ratio allows for the higher molar ratio of ammonia required to react with the NO_2. The heat rate penalty cost item reflects the cost due to the SCR back pressure losses. The additional back pressure will derate the combustion turbine resulting in lost electric sales revenue. The costs associated with these impacts are included in the annual cost estimate.

The use of an SCR system increases the energy requirements of the Project. The SCR system requires vaporizers and blowers to vaporize and dilute the anhydrous ammonia reagent for injection. Increased NO_x reduction rates require increased ammonia consumption resulting in increased power consumption of the Project. Maintenance costs consist of routine SCR system maintenance. The replacement materials are assumed to be two percent of the original cost for equipment and labor is assumed to be equal to materials.

Total 1999 annual costs for the NO_x control system are calculated as the sum of 1999 operating costs plus capital recovery factor. The total annual cost per unit for a 5.0 (gas)/42.0 (oil) ppmvd NO_x outlet emission SCR system for the 7FA combustion turbines is estimated to be $1,236,000. This annual cost results in a cost effectiveness per ton of NO_x removed of approximately $13,380.

4.3.1.2 Energy Impacts.

The use of an SCR system impacts the energy requirements of the Project. The SCR system requires vaporizers and blowers to vaporize and dilute the anhydrous ammonia reagent for injection. In addition, an SCR system catalyst will increase the back pressure on each combustion turbine. The SCR system will add 1.5 inches water gauge (in. w.g.) back pressure to each type of unit. This will reduce the output of each combustion turbine by approximately 0.19 percent. Increased power consumption and lost power generation are included in the annual cost estimate.

4.3.1.3 Environmental Impacts.

The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). However, the storage and use of ammonia has been a relatively routine practice in utility power plants and industrial plant processes. With proper precautions, anhydrous ammonia can be stored and used safely.

Some ammonia slip from the combustion turbine stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppmvd (uncorrected), unless that limit is shown to be inappropriate. At least one air pollution control district in California recently set an ammonia slip emissions limit of 10 ppmvd (uncorrected). Ammonia slip emissions from an SCR system is a design consideration that establishes catalyst life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictates associated catalyst replacement. A design value of 10 ppmvd (uncorrected) is appropriate for a clean fuel facility such as this Project. With fresh catalyst ammonia slip emissions will be very low. However, as the catalyst deactivates, ammonia slip will increase approaching the design value at the end of the guaranteed catalyst life.

Over time, with exposure to trace elements in the flue gas, SCR catalysts can become contaminated and, depending on the type of contamination, may be classified as a hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures.

When firing fuel oil or any sulfur bearing fuel, the SCR catalyst will oxidize approximately 2 to 3 percent of the SO_2 in the flue gas to SO_3. Once the flue gas cools below approximately 600 F the ammonia present in the flue gas may react with the SO_3 to form ammonium sulfate and bisulfate salts. This may formation may be dependent on the particular plume dispersion characteristics at the given time of stack discharge since this temperature will only be reached once the flue gas has left the stack. However, if the ammonia sulfate compounds are not formed, the SO3 will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Any ammonium sulfate and bisulfate salts and sulfuric acid mist formed will increase the amount of particulate matter emitted in the flue gas. This particulate will predominately consist of matter less than 10 microns in diameter (PM_{10}).

4.4 Conclusions

SCR systems are representative of the LAER level of NO_x emissions reduction. SCR systems have been successfully used on numerous combined cycle combustion turbine applications but have limited experience mixed results on SCCT applications. The fundamental obstacle to the use of these systems on a SSCT is the overall economics and the potential primary (SO_2 to SO_3 oxidation) and secondary (ammonium bisulfate deposits and increased PM_{10} emissions) environmental impacts when firing sulfur bearing fuels. NO_x reduction costs for the proposed turbines are $13,380 per ton of removed NO_x. This overall annual cost of the SCR to meet NO_x emission limits of 5.0 ppmvd (natural gas firing) and 42.0 ppmvd (fuel oil firing) is judged to be excessive. In addition, SCR use will result in additional PM_{10} emissions caused by the additional SO_2 to SO_3 oxidation and associated ammonium bisulfate/sulfate and H_2SO_4 emissions. Therefore, based on energy, environmental, and economic impacts, the use of dry low NO_x combustors to meet an emissions level of 12 ppmvd during natural gas firing and water injection to meet an emission limit of 42 ppmvd during fuel oil firing is recommended as BACT for the proposed General Electric 7FA combustion turbines. This proposed limit is considered consistent with the range of emission limits allowed for other recent permits allowed in the U.S. and the State of Florida.

5.0 CO BACT

The objective of this analysis is to determine BACT for CO emissions from the combustion turbines.

5.1 BACT/LAER Clearinghouse Reviews

A review of the BACT/LAER Clearinghouse documents indicates that the most stringent CO emission level for a combustion turbine is 1.8 ppmvd at 15 percent O_2 for the Newark Bay Cogeneration L.P. project located in New Jersey. These emissions are achieved by reducing CO emissions through the use of an oxidation catalyst. It should be noted that the Newark Bay project is located in non-attainment areas for CO and ozone (VOC control required) and therfore represents LAER. A summary listing of recent BACT determinations is presented in Appendix A.

Recent applications in the State of Florida include the City of Tallahassee (25 ppm on gas and 90 ppm on oil), the FPC Hines project (25 ppm on gas and 30 ppm on oil), and the Tiger Bay project (15 ppm on gas and 30 ppm on oil).

5.2 Alternative CO Emission Reduction Systems

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO. CO is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures through steam/water injection or staged combustion, which is used to reduce combustor based NO_x formation, can be counterproductive with regard to CO emissions.

The only CO reduction technology available that will not impact NO_x emissions is the use of an oxidation catalyst to convert the CO to CO_2. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components are considered toxic. No reagent injection is necessary and oxidizing catalysts are capable of reducing CO emissions by up to 90 percent. The already very low emissions on the 7FA machine of 15 ppm is expected to limit any additional emissions reductions on gas firing to 1.8 ppmvd @ 15% O_2 (88 percent removal) if a catalyst is used. Reductions on oil is also expected to be 88 percent (2.4 ppmvd @ 15% O_2). The estimated CO emissions for the control technology are listed in Table 5-1.

5.3 Evaluation of Feasible Technologies

The following evaluation considers economic, energy, and environmental impacts for the potential BACT scenario's evaluated.

5.3.1 Economic Impacts

The use of oxidation catalyst has a significant negative economic impact to the Project. Analysis of the economic impacts is provided below. The CO BACT costs presented in this analysis are based on operating the General Electric 7FA unit at full load for 4,000 hour per year on natural gas and 800 hours per year on No. 2 fuel oil.

5.3.1.1 Capital costs.

Tables 5-2 presents the capital costs for installing an oxidation catalyst system on a General Electric 7FA. The capital costs for the systems includes the oxidation catalytic reactor and balance of plant equipment, and were based on budgetary quotations from equipment manufacturers and other engineering estimates.

5.3.1.2 Operating costs.

Table 5-3 presents the annual operating costs and emission rates using an oxidation catalyst to achieve 88 percent reduction of CO on a General Electric 7FA. CO outlet emissions would be reduced to a maximum of 1.8 ppmvd at 15 percent O_2 during natural gas firing and 2.4 ppmvd during gas firing and fuel oil firing, respectively. Annual operating costs for the systems include catalyst replacement, operating personnel, maintenance costs, and lost power generation. Throughout the life of the plant, catalyst elements will require periodic replacement. Currently, catalyst manufacturers are willing to guarantee a catalyst life of three years of equivalent operating hours) for an oxidation catalyst. The catalyst life is adjusted to account for the abbreviated operating hours each year of the peaking unit.

Total 1999 annual cost for the oxidation catalyst system is calculated as the sum of the 1999 annual operating costs plus capital recovery. The total annual operating cost for an oxidation catalyst is estimated to be $509,000. This results in an incremental CO removal cost of $4,740.

Table 5-1
Estimated CO Emissions From
Alternate Control Technologies Per GE 7FA Unit

Fuel	Control Technologies	
	Dry Low NO_x Combustors	Oxidation Catalyst 88% Reduction
Natural Gas		
Ppmvd	15	1.8
Tons per year[a]	96	11.5
Fuel Oil		
Ppmvd	20	2.4
Tons per year[b]	26	3.1
BACT Basis (Annual)[c]		
Tons per year	122	14.6

Notes:

[a] Annual emissions based on 4,000 hours of operation per year at full load rating with an ambient temperature of 59 degree F.

[b] Annual emissions are based on 800 hours of operation per year at full load rating with an ambient temperature of 59 degree F.

[c] Annual emissions are based on firing natural gas for 4,000 hours and No. 2 fuel oil for 800 hours per year at full load rating with an ambient temperature of 59 degree F.

Table 5-2
CO Reduction System Capital Cost Per GE 7FA

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Capital Cost			
Catalysts	712,000	NA	Scaled from previous vendors quotes
Catalyst Reactor	245,000	NA	Calculated based on catalyst size
Dilution Air System	282,000	NA	Estimated for entire fan system
Control/Instrumentation	40,000	NA	Estimated
Balance of Plant	192,000	NA	For: 15% For Foundations & Supports, Erection, Electrical Installation, Painting, Insulation, Vendor Engineering.
Total Direct Capital Cost	1,471,000	Base	
Indirect Capital Costs			
Contingency	294,000	NA	20% of Direct Capital Cost
Engineering and Supervision	74,000	NA	5% of Direct Capital Cost
Construction & Field Expense	29,000	NA	2% of Direct Capital Cost
Construction Fee	15,000	NA	1% of Direct Capital Cost
Start-up Assistance	15,000	NA	1% of Direct Capital Cost
Performance Test	7,000	NA	0.5% of Direct Capital Cost
Total Indirect Capital Costs	434,000	Base	
Total Installed Cost	**1,905,000**	Base	

Table 5-3
CO Reduction System Annual Cost Per GE 7FA

	Oxidation Catalyst	Good Combustion Controls	Remarks
Direct Annual Cost			Cost based on emissions in Table 5-1
Catalyst Replacement	143,000	NA	Catalyst life of 3 yr. of equivalent operating hours
Operation and Maintenance	0	NA	See text for background information on this item
Power Consumption	29,000	NA	Includes back pressure on combustion turbine and dilution air fan energy consumption
Lost Power Generation	34,000	NA	
Total Direct Annual Cost	206,000	NA	
Indirect Annual Costs Indirect Annual Costs			
Overhead	0	NA	60% of Operating and Maintenance Labor
Administrative Charges	38,000	NA	2% of Total Installed Cost
Property Taxes	52,000	NA	2.75% of Total Installed Cost
Insurance	19,000	NA	1% of Total Installed Cost
Capital Recovery	194,000	NA	Capital Recovery Factor * Total Installed Cost
Total Indirect Annual Costs	303,000	NA	
Total Annual Cost	**509,000**	NA	
Annual Emissions, tpy	14.6	122.0	Emissions taken from Table 5-1
Emissions Reduction, tpy	107.4	NA	Emissions calculated from Table 5-1
Total Cost Effectiveness, $/ton	4,740	NA	Total Annual Cost/Emissions Reduction

5.3.1.3 Energy Impacts

An oxidation catalyst reactor located downstream of the combustion turbine exhaust will increase the back pressure on the combustion turbine. The additional back pressure of 1.5 inches, water gauge, will reduce the CT output by approximately 0.19 percent. The cost of lost power revenue due to the back pressure is included in the economic analysis.

5.3.1.4 Environmental Impacts

The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions from sources firing fuel oil is that a significant percentage of the SO_2 in the flue gas will oxidize to SO_3. The higher the operating temperature the higher the SO_2 to SO_3 oxidation potential. It is estimated that between 75 and 90 percent of the SO_2 in the flue gas will oxidize to SO_3 as a result of the CO oxidation catalyst being installed after the CT outlet with high temperatures. The SO3 will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. This is a substantial concern, especially since the unit will fire oil as alternate fuel, since increased H_2SO_4 emissions would increase PM_{10} emissions from the Project. This particulate matter will predominately consist of matter less than 10 microns in diameter (PM_{10}).

5.4 Conclusions

Installation of an oxidation catalyst system designed to reduce CO emissions by 88 percent would add approximately $509,000 to the annual operating capital cost of a GE 7FA. The resultant cost effectiveness on a per ton of CO removed basis is $4,740/ton. This is an excessivley high cost for this non-criteria pollutant. CO catalysts have not typically been applied to similar applications under BACT consideration. The emissions emitted from the CT of 15.0 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing represent emission levels lower than other recent projects that the State has permitted. Therefore, based on economic, environmental (especially with regard to PM_{10} emissions), and energy impacts, the proposed CO BACT for the control of CO emissions from each CT is good combustion practices using advanced combustion controls design. Emissions for the GE 7FA will be limited to 15.0 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing.

6.0 PM/PM_{10} Emissions Control

The emissions of particulate matter from the Project will be controlled by ensuring as complete combustion of the fuel as possible and by minimizing SO_2 to SO_3 oxidation. The NSPS for combustion turbines do not establish an emission limit for particulate. Natural gas contains only trace quantities of non-combustible material.

The manufacturer's standard operating procedures include filtering the turbine inlet air and combustion controls. The BACT/LAER Clearinghouse documents do not list any post-combustion particulate matter control technologies being used on combustion turbines. Consistent with the previous determinations as recently referenced by the State of Florida, such as the FPL Fort Myers (Florida), Santa Rosa (Florida), and the City of Tallahasse (Florida) projects, the use of combustion controls is considered BACT for particulate matter and is proposed for this project.. Particulate emissions (front half catch only) will be limited to 0.0055 lb/mmbtu (9 lb/hr at full load) while firing natural gas and 0.0093 lb/mmbtu (17 lb/hr at full load) while firing oil.

7.0 SO2 BACT Analysis

Typically, natural gas has only trace amounts of sulfur that is used as an odorant. Fuel oil will be limited to less than 0.5 percent sulfur. The selection of these fuels provide inherently low SO_2 emissions. No supplemental SO_2 emission controls have been imposed on natural gas fired combustion turbines by regulatory agencies. Other recent Florida projects hav identified the use of natural gas and low sulfur oil as BACT. Since the project will be using typical natural gas as the fuel and low sulfur oil as a limited alternative fuel, the use of these fuels are considered BACT.

8.0 Summary

The following is a summary of BACT for the combustion turbines and the associated emission rates.

- Nitrogen oxides (NO_x) emissions -- Dry low NO_x burners during natural gas and fuel oil firing to achieve an emission limit of 12 ppmvd and 42 ppmvd respectively at 15 percent O_2

- Carbon monoxide (CO) emissions -- Good combustion controls to achieve a CO emission limit of 15 ppmvd during natural gas firing and 20 ppmvd during fuel oil firing.

- Particulate emissions--Good combustion controls.

- Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) —Good combustion controls using natural gas and fuel oil with less than 0.5 percent sulfur.

Appendix A
BACT Clearinghouse Summary

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
NEWARK BAY COGENERATION PARTNERSHIP	NJ		11/1/90	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	CO	0.0055	LB/MMBTU	CATALYTIC OXIDATION	80	BACT-PSD
CNG TRANSMISSION	OH	Jan-70	8/12/92	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	CO	0.015	G/HP-HR	FUEL SPEC: USE OF NATURAL GAS		OTHER
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL (SEE NOTES)	4/1/91	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	CO	0.026	LB/MMBTU	TURBINE DESIGN		BACT-OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	BURNERS, DUCT (2)	553 MMBTU/HR EACH	CO	0.06	LB/MMBTU	OXIDATION CATALYST		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNER	123 MMBTU/HR	CO	0.072	LB/MMBTU GAS (100%)	COMBUSTION CONTROL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNERS (2)	206 MMBTU/HR (EACH)	CO	0.073	LB/MMBTU GAS, 100%	COMBUSTION CONTROLS		BACT-OTHER
ALGONQUIN GAS TRANSMISSION CO.	RI	1126-1127	7/31/91	TURBINE, GAS, 2	49 MMBTU/H	CO	0.114	LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-OTHER
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	DUCT BURNER, GAS	150 MMBTU/H	CO	0.2	LB/MMBTU	NOT REQUIRED		BACT-PSD
FLORIDA GAS TRANSMISSION COMPANY	AL	503-3028-X003	8/5/93	TURBINE, NATURAL GAS	12600 BHP	CO	0.42	GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY COMBUSTION CONTROLS		BACT-PSD
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	2 GAS-FIRED GENERATOR ENGINES	385 HORSEPOWER	CO	1.3	LBS/HR	GOOD COMBUSTION		BACT
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	CO	1.8	PPMDV	OXIDATION CATALYST		OTHER
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	1 GAS-FIRED GENERATOR ENGINE	577 HORSEPOWER	CO	1.9	LBS/HR	GOOD COMBUSTION		BACT
TEMPLE UNIVERSITY	PA	92310	10/2/92	ELECTRIC GENERATOR (NATURAL GAS)	1.6 MW	CO	1.92	GRAMS/BHP-HR	LEAN BURN GAS ENGINE		BACT-OTHER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, KEROSENE-FIRED (2)	640 MMBTU/H (EACH)	CO	2.6	PPMDV	OXIDATION CATALYST		OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	CO	3	PPM	OXIDATION CATALYST		BACT-OTHER
BLUE MOUNTAIN POWER, LP	PA	09-328-009	7/31/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	CO	3.1	PPM @ 15% O2	OXIDATION CATALYST 16 PPM @ 15% O2 WHEN FIRING NO. 2 OIL. AT 75% NG LIMIT SET TO 22.1 PPM	80	OTHER
NORTHWEST PIPELINE CORPORATION	CO	91LP792(1-2) MOD. #1	5/29/92	BURNERS, DUCT, COEN	29 MMBTU/HR PER BURNER	CO	4	LB/HR			OTHER
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	2-6101-00185/00002-9	6/6/95	TURBINE, NATURAL GAS FIRED	240 MW	CO	4	PPM @ 15% O2			LAER
SUMAS ENERGY INC.	WA		6/25/91	TURBINE, NATURAL GAS	88 MW	CO	6	PPM @ 15% O2	CO CATALYST	80	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2046009-011	10/29/91	TURBINE, GAS FIRED, SOLAR MODEL H	5500 HP	CO	7.74	PPM @ 15% O2	HIGH TEMP OXIDATION CATALYST	80	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2046009-011	10/29/91	TURBINE, GAS-FIRED	47.64 MMBTU/H	CO	7.74	PPM @ 15% O2	HIGH TEMPERATURE OXIDATION CATALYST	80	BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00926/00001-9	9/1/92	TURBINE, COMBUSTION GAS (150 MW)	MMBTU/HR 1146 (GAS)*	CO	8.5	PPM	COMBUSTION CONTROL		BACT-OTHER
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	MMBTU/H, NAT 1032 GAS	CO	9	PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
MID-GEORGIA COGEN.	GA	4911-076-11753	4/3/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	CO	10	PPMVD	COMPLETE COMBUSTION		BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINES (2) (252 MW)	MMBTU/HR 1173 (EACH)	CO	10	PPM	COMBUSTION CONTROLS		BACT-OTHER
TIGER BAY LP	FL	PSD-FL-190	5/17/93	DUCT BURNER, GAS	100 MMBTU/H	CO	10	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
UNOCAL	CA	A/N 168294 AND 168295	7/18/89	TURBINE, GAS (SEE NOTES)		CO	10	PPM @ 15% O2	OXIDATION CATALYST	75	BACT-OTHER
ORLANDO UTILITIES COMMISSION	FL	PSD-FL-173	11/5/91	TURBINE, GAS, 4 EACH	35 MW	CO	10	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	CO	10.5	PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX		BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	CO	10.5	PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX		BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	RI-PSD-4	4/13/92	TURBINE, GAS AND DUCT BURNER	MMBTU/H 1360 EACH	CO	11	PPM @ 15% O2, GAS			BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	NY	7-3556-00040-00007-9	11/24/92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	MMBTU/HR 2133 (EACH)	CO	13	PPM	COMBUSTION CONTROLS		BACT-OTHER
MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	NM	PSD-NM-295-M-2	1/11/95	TURBINES, NATURAL GAS (2)	5500 HP	CO	13.2	LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY.	66	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	CO	15	PPMVD	GOOD COMBUSTION PRACTICES		BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	OR	25-0031	5/31/94	TURBINES, NATURAL GAS (2)	1720 MMBTU	CO	15	PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
HERMISTON GENERATING CO.	OR	30-0113	4/1/94	TURBINES, NATURAL GAS (2)	1696 MMBTU	CO	15	PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	CO	20	PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-PSD
KEY WEST CITY ELECTRIC SYSTEM	FL	AC44-245399 / PSD-FL-210	9/28/95	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	CO	20	PPM @ 15% O2 FULL LD	GOOD COMBUSTION		BACT-PSD
KALAMAZOO POWER LIMITED	MI	1234-90	12/3/91	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1805.9 MMBTU/H	CO	20	PPMV	DRY LOW NOX TURBINES		BACT-PSD
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	MMBTU/H 385 EACH TURBINE	CO	22.4	PPM @ 15% O2			BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	CO	23	LBS/HR	GOOD COMBUSTION PRACTICES		BACT-PSD
PANDA-KATHLEEN, L.P.	FL	AC53-251898/PSD-FL-216	6/1/95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	CO	25	PPM @ 15% O2	COMBUSTION CONTROLS STANDARD ONLY APPLIES IF GE CT IS SELECTED, THE ABB CT WAS LESS THAN SIGNIFICANT EMIS. INCR FOR CO		BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	CO	25	PPM	COMBUSTION CONTROL		BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10941	7/28/92	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	CO	25	PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	9/WE667(1-5)	2/19/92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	CO	25	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
CHARLES LARSEN POWER PLANT	FL	PSD-FL-166	7/25/91	TURBINE, GAS, 1 EACH	80 MW	CO	25	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	CO	25	PPMVD	GOOD COMBUSTION PRACTICES		BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	PSD-LA-560 (M-1)	3/2/95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	CO	25.8	LB/HR	PROPER OPERATION		BACT-PSD
LORDSBURG L.P.	NM	PSD-NM-1975	6/18/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	CO	27	LBS/HR	DRY LOW-NOX TECHNOLOGY BY MAINTAINING PROPER AIR-FUEL RATIO.		BACT-PSD
MILAGRO, WILLIAMS FIELD SERVICE	NM	PSD-NM-859-M-4		TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	CO	27.6	PPM @ 15% O2			BACT-PSD
MEAD COATED BOARD, INC.	AL	211-0004	3/12/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	CO	28	PPMVD@15% O2 (GAS)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, GAS, 4 EACH	400 MW	CO	30	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	CO	30	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
ORANGE COGENERATION LP	FL	PSD-FL-206	12/30/93	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	CO	30	PPMVD	GOOD COMBUSTION		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, CG, 4 EACH	400 MW	CO	33	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	A391	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	CO	39.98	LBS/HR	CATALYTIC CONVERTER		BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	A360	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	CO	39.98	LBS/HR	CATALYTIC CONVERTER		BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	MA	MBR-89-COM-032	11/30/89	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	CO	40	PPM @ 15% O2	GOOD COMBUSTION PRACTICES		BACT-OTHER
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	367 MMBTU/H	CO	40	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	TURBINE, GAS, 2 EACH	42 MW	CO	42	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
TIGER BAY LP	FL	PSD-FL-190	5/17/93	TURBINE, GAS	1614.8 MMBTU/H	CO	49	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
BUCKNELL UNIVERSITY	PA	60-0001A	11/26/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	CO	50	PPMV@15%O2	GOOD COMBUSTION		BACT-OTHER
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	PSD-NM-340M2	10/29/93	TURBINE, GAS-FIRED	11257 HP	CO	50	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	869 MMBTU/H	CO	54	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	CO	59	LB/HR	COMBUSTION CONTROL		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	CO	60	LB/HR	COMBUSTION CONTROL		BACT-PSD
ENRON LOUISIANA ENERGY COMPANY	LA	PSD-LA-569	8/5/91	TURBINE, GAS, 2	39.1 MMBTU/H	CO	60	PPM @ 15% O2	BASE CASE, NO ADDITIONAL CONTROLS		BACT-PSD
EL PASO NATURAL GAS	AZ		10/18/91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	CO	60	PPM @ 15% O2	LEAN BURN		BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	LA	PSD-LA-560 (M-2)	3/7/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	CO	70	LB/HR	COMBUSTION DESIGN AND CONSTRUCTION.		BACT-PSD
PHOENIX POWER PARTNERS	CO	92WEI357	5/11/93	GENERATOR, STEAM, W/ DUCT BURNER	50 MMBTU/HR	CO	91.18	TPY	FUEL SPEC: NATURAL GAS COMBUSTION		OTHER
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	GE LM-5000 GAS TURBINE	550 MMBTU/HR	CO	92	LB/HR TEMP > 20F	NO CONTROLS		BACT-OTHER
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	STACK (TURBINE AND DUCT BURNER)	715 MMBTU/HR	CO	106.4	LB/HR TEMP > 20F	OXIDATION CATALYST	80	BACT
NORTHERN CONSOLIDATED POWER	PA	25-328-001	5/3/91	TURBINES, GAS, 2	34.6 KW EACH	CO	110	T/YR	OXIDATION CATALYST	90	OTHER
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	A533	9/18/92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	CO	152.5	TPY (EACH TURBINE)	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR		BACT-PSD
INTERNATIONAL PAPER	LA	PSD-LA-93(M-3)	2/24/94	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	CO	165.9	LB/HR	COMBUSTION CONTROL		BACT
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	DUCT BURNER	710 MM BTU/HR	CO	198.6	LB/HR COMMON VENT	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE		BACT-PSD
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	GENERATOR, GAS TURBINE	1313 MM BTU/HR	CO	198.6	LB/HR	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE		BACT-PSD
CIMARRON CHEMICAL	CO	90WE438	3/25/91	TURBINE #2, GE FRAME 6	33 MW	CO	250	T/YR, LESS THAN	CO CATALYST		OTHER
WEST CAMPUS COGENERATION COMPANY	TX	23962/PSD-TX-837	5/2/94	GAS TURBINES	75.3 MW (TOTAL POWER)	CO	300	TPY	INTERNAL COMBUSTION CONTROLS		BACT
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	DUCT BURNER	450 MM BTU/HR	CO	600	MM BTU/HR CAP FOR 3	GOOD COMBUSTION PRACTICE AND PROPER OPERATION		BACT-PSD
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	CO	972.4	TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	CO		SEE FACILITY NOTES	GOOD COMBUSTION PRACTICES		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	CO, GAS	33	PPMDV	COMBUSTION CONTROLS.		BACT-PSD
PORTSIDE ENERGY CORP.	IN	CP 127 5260	5/13/96	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	CO, NON-POWER MODE	12	LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 10 PPMVD AT 15% OXYGEN.		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	CO, OIL	100	PPMDV AT MIN. LOAD	COMBUSTION CONTROLS.		BACT-PSD
PORTSIDE ENERGY CORP.	IN	CP 127 5260	5/13/96	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	CO, POWER MODE	40	LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 40 PPMVD AT 15% OXYGEN.		BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	H2SO4	7.5	LB/H	FUEL SPEC: LOW SULFUR IN NATURAL GAS		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	H2SO4	25.1	LB/HR	FUEL SPEC: 0.2% SULFUR FUEL OIL		BACT-PSD
CHARLES LARSEN POWER PLANT	FL	PSD-FL-166	7/25/91	TURBINE, GAS, 1 EACH	80 MW	H2SO4			FUEL SPEC: LIMIT FUEL SULFUR CONTENT		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	H2SO4			FUEL SPEC: NATURAL GAS AS FUEL		BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNERS (2)	206 MMBTU/HR (EACH)	H2SO4 MIST	0.0035	LB/MMBTU	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	H2SO4 MIST	0.021	LB/MMBTU OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
MILAGRO, WILLIAMS FIELD SERVICE	NM	PSD-NM-859-M-4		TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	NO2	9	PPM @ 15% O2	DRY LOW NOX (GENERAL ELECTRIC MODEL PG6541B)	94	BACT-PSD
ALABAMA POWER COMPANY	AL	108-0018-X001 AND -X002	12/17/97	COMBUSTION TURBINE W/ DUCT BURNER (COMBINED CYCLE)	100 MW	NO2	15	PPM	DRY LOW NOX BURNERS		BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	NO2	15	PPM @ 15% O2	DRY BURN LOW NOX BURNERS	91	BACT-PSD
PEPCO - CHALK POINT PLANT	MD		6/25/90	TURBINE, 105 MW OIL FIRED ELECTRIC	105 MW	NO2	25	PPM @ 15% O2	DRY PREMIX BURNER		BACT-PSD
PEPCO - CHALK POINT PLANT	MD		6/25/90	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84 MW	NO2	25	PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION		BACT-PSD
LINDEN COGENERATION TECHNOLOGY	NJ		1/21/92	TURBINE, NATURAL GAS FIRED	50 X E12 BTU/YR	NO2	33.8	LB/HR	STEAM INJECTION AND SCR	94.5	BACT-PSD
PEPCO - STATION A	MD		5/31/90	TURBINE, 124 MW NATURAL GAS FIRED	125 MW	NO2	42	PPM @ 15% O2	WATER INJECTION		BACT-PSD
SOUTHERN NATURAL GAS	AL	412-0013-X001 AND -X002	3/4/98	2-9160 HP GE MODEL MS3002G NATURAL GAS TURBINES	9160 HP	NO2	53	LB/HR			BACT-PSD
SOUTHERN NATURAL GAS	AL	206-0021-X001 AND -X002	3/2/98	9160 HP GE MODEL M53002G NATURAL GAS FIRED TURBINE	9160 HP	NO2	53	LB/HR			BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	A391	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	NO2	61.26	LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT		BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	A360	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	NO2	61.26	LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT		BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE, 140 MW OIL FIRED ELECTRIC	140 MW	NO2	65	PPM @ 15% O2	WATER INJECTION	72	BACT-PSD
LORDSBURG L.P.	NM	PSD-NM-1975	6/18/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	NO2	74.4	LBS/HR	DRY LOW-NOX TECHNOLOGY WHICH ADOPTS STAGED OR SCHEDULED COMBUSTION.	80	BACT-PSD
PEPCO - CHALK POINT PLANT	MD		6/25/90	TURBINE, 105 MW NATURAL GAS FIRED ELECTRIC	105 MW	NO2	77	PPM @ 15% O2	DRY PREMIX AND WATER INJECTION		BACT-PSD
PEPCO - STATION A	MD		5/31/90	TURBINE, 124 MW OIL FIRED	125 MW	NO2	77	PPM @ 15% O2	WATER INJECTION		BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	A533	9/18/92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	NO2	88.6	TPY (EACH TURBINE)	LOW NOX COMBUSTOR		BACT-PSD
NORTHWEST PIPELINE COMPANY	WA	92-4	8/13/92	TURBINE, GAS-FIRED	12100 HP	NO2	196	PPM @ 15% O2	ADVANCED DRY LOW NOX COMBUSTOR (BY 07/01/95)	76	BACT-PSD
PACIFIC GAS TRANSMISSION COMPANY	OR	16-0026	6/19/90	TURBINE GAS, COMPRESSOR STATION	110 MMBTU/HR	NO2	199	PPM @ 15% O2	LOW NOX BURNER DESIGN	30	NSPS
SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	MD		10/1/89	TURBINE, NATURAL GAS FIRED ELECTRIC	90 MW	NO2	199	LB/HR	WATER INJECTION		BACT-PSD
CITY OF ST.PAUL POWER PLANT	AK	9625-AA004	6/27/96	INTERNAL COMBUSTION	3.4 MW	NO2	427	TPY	AFTERCOOLERS		BACT-PSD
CITY OF UNALASKA	AK	9625-AA003	6/21/96	INTERNAL COMBUSTION	6.5 MW	NO2	632.6	TPY	LIMIT OF OPERATION HOURS AND AFTERCOOL		BACT-PSD

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SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNERS (2)	MMBTU/HR 206 (EACH)	NOX	0.0181	LB/MMBTU GAS	LOW NOX BURNER AND SCR		BACT-OTHER
NEWARK BAY COGENERATION PARTNERSHIP	NJ		11/1/90	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	NOX	0.033	LB/MMBTU	STEAM INJECTION AND SCR	94	BACT-PSD
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL (SEE NOTES)	4/1/91	TURBINES (NATURAL GAS) (2)	MMBTU/HR 1190 (EACH)	NOX	0.033	LB/MMBTU	SCR, DRY LOW NOX BURNER	64	BACT-OTHER
NUGGET OIL CO.	CA	4131003	10/8/91	GENERATOR, STEAM, GAS FIRED	62.5 MMBTU/H	NOX	0.043	LB/MMBTU	LOW NOX BURNER AND FLUE GAS RECIRCULATION*	57	BACT-PSD
PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	NJ		2/23/90	TURBINE, NATURAL GAS FIRED	1000 MMBTU/HR	NOX	0.044	LB/MMBTU	STEAM INJECTION AND SCR	93	BACT-PSD
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	BURNERS, DUCT (2)	MMBTU/HR 553 EACH	NOX	0.08	LB/MMBTU	SCR		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNER	123 MMBTU/HR	NOX	0.091	LB/MMBTU, GAS	LOW NOX BURNER		BACT-OTHER
KAMINE/BESICORP CORNING L.P.	NY	8-4638-00022/01-0	11/5/92	BURNER, DUCT	90 MMBTU/HR	NOX	0.1	LB/MMBTU	LOW NOX BURNER		BACT-OTHER
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	DUCT BURNER	710 MM BTU/HR	NOX	0.1	LB/MM BTU	LOW NOX BURNERS		BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	DUCT BURNER, GAS	150 MMBTU/H	NOX	0.1	LB/MMBTU	NOT REQUIRED		BACT-PSD
TIGER BAY LP	FL	PSD-FL-190	5/17/93	DUCT BURNER, GAS	100 MMBTU/H	NOX	0.1	LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-PSD
TEMPO PLASTICS	CA	S-995-5-0	12/31/96	GAS TURBINE COGENERATION UNIT		NOX	0.109	LB/MMBTU	LOW-NOX COMBUSTOR		LAER
FLORIDA GAS TRANSMISSION COMPANY	AL	503-3028-X003	8/5/93	TURBINE, NATURAL GAS	12600 BHP	NOX	0.58	GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY LOW NOX COMBUSTION	71	BACT-PSD
CNG TRANSMISSION	OH	Jan-70	8/12/92	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	NOX	1.6	G/HP-HR*	LOW NOX COMBUSTION		BACT-OTHER
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	2 GAS-FIRED GENERATOR ENGINES	385 HORSEPOWER	NOX	1.7	LBS/HR	RETROFIT W/AN AIR TO FUEL RATIO CONTROL W/ NON-SELECTIVE CATALYTIC REDUCTION (NSCR)		BACT
TEMPLE UNIVERSITY	PA	92310	10/2/92	ELECTRIC GENERATOR (NATURAL GAS)	1.6 MW	NOX	2	GRAM/BHP-HR	LEAN BURN GAS ENGINE		BACT-OTHER
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	1 GAS-FIRED GENERATOR ENGINE	577 HORSEPOWER	NOX	2.5	LBS/HR	RETROFIT W/AN AIR TO FUEL RATIO CONTROL W/ NON-SELECTIVE CATALYTIC REDUCTION (NSCR)		BACT
GRANITE ROAD LIMITED	CA	4216001	5/6/91	TURBINE, GAS, ELECTRIC GENERATION	460.9 MMBTU/H*	NOX	3.5	PPMVD @ 15% O2	SCR, STEAM INJECTION	97	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	2-6101-00185/00002-9	6/6/95	TURBINE, NATURAL GAS FIRED	240 MW	NOX	3.5	PPM @ 15% O2	SCR		LAER
BLUE MOUNTAIN POWER, LP	PA	09-328-009	7/31/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	NOX	4	PPM @ 15% O2	DRY LNB WITH SCR WATER INJECTION IN PLACE WHEN FIRING OIL. OIL FIRING LIMITS SET TO 8.4 PPM @15% O2	84	LAER
SITHE/INDEPENDENCE POWER PARTNERS	NY	7-3556-00040-00007-9	11/24/92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	MMBTU/HR 2133 (EACH)	NOX	4.5	PPM	SCR AND DRY LOW NOX		BACT-OTHER
PORTLAND GENERAL ELECTRIC CO.	OR	25-0031	5/31/94	TURBINES, NATURAL GAS (2)	1720 MMBTU	NOX	4.5	PPM @ 15% O2	SCR	82	BACT-PSD

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HERMISTON GENERATING CO.	OR	30-0113	4/1/94	TURBINES, NATURAL GAS (2)	1696 MMBTU	NOX	4.5	PPM @ 15% O2	SCR	82	BACT-PSD
GOAL LINE, LP ICEFLOE	CA	911504	11/3/92	TURBINE, COMBUSTION (NATURAL GAS) (42.4 MW)	386 MMBTU/HR	NOX	5	PPMVD @ 15% OXYGEN	WATER INJECTION & SCR W/ AUTOMATIC AMMONIA INJECT.	88	BACT-OTHER
SUMAS ENERGY INC.	WA		6/25/91	TURBINE, NATURAL GAS	88 MW	NOX	6	PPM @ 15% O2	SCR	90	BACT-PSD
KINGSBURG ENERGY SYSTEMS	CA	3040230101	9/28/89	TURBINE, NATURAL GAS FIRED, DUCT BURNER	34.5 MW	NOX	6	PPM @ 15% O2	SCR, STEAM INJECTION	90	BACT-PSD
MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	NM	PSD-NM-295-M-2	1/11/95	TURBINES, NATURAL GAS (2)	5500 HP	NOX	7.4	LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY. DRY/LOW NOX	66	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2046009-011	10/29/91	TURBINE, GAS FIRED, SOLAR MODEL H	5500 HP	NOX	8	PPM @ 15% O2	HIGH TEMP SELECT. CAT. REDUCTION	93	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2046009-011	10/29/91	TURBINE, GAS-FIRED	47.64 MMBTU/H	NOX	8	PPMVD @ 15% O2	HIGH TEMPERATURE SELECTIVE CATALYTIC REDUCTION	93	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	NOX	8.3	PPMDV	SCR		BACT-PSD
MID-GEORGIA COGEN.	GA	4911-076-11753	4/3/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	NOX	9	PPMVD	DRY LOW NOX BURNER WITH SCR		BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	NOX	9	PPM GAS	STEAM INJECTION AND SCR		BACT-OTHER
CIMARRON CHEMICAL	CO	90WE438	3/25/91	TURBINE #2, GE FRAME 6	33 MW	NOX	9	PPM @ 15% O2	SCR		OTHER
KAMINE/BESICORP CORNING L.P.	NY	8-4638-00022/01-0	11/5/92	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	NOX	9	PPM	DRY LOW NOX OR SCR		BACT-OTHER
SEMINOLE FERTILIZER CORPORATION	FL	PSD-FL-157	3/17/91	TURBINE, GAS	26 MW	NOX	9	PPM @ 15% O2	SCR		BACT-PSD
UNOCAL	CA	A/N 168294 AND 168295	7/18/89	TURBINE, GAS (SEE NOTES)		NOX	9	PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION (SCR), WATER INJECTN	80	BACT-OTHER
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	RI-PSD-4	4/13/92	TURBINE, GAS AND DUCT BURNER	1360 MMBTU/H EACH	NOX	9	PPM @ 15% O2, GAS	SCR		BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	PSD-LA-560 (M-1)	3/2/95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	NOX	9	PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONTROL		LAER
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	LA	PSD-LA-560 (M-2)	3/7/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	NOX	9	PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONSTRUCTION.		BACT-PSD
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	NOX	9	PPM	SCR		BACT-OTHER
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	NOX	12	PPMVD @15 % O2	DRY LOW NOX COMBUSTOR		BACT-PSD
PANDA-KATHLEEN, L.P.	FL	AC53-251898/PSD-FL-216	6/1/95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	NOX	15	PPM @ 15% O2	DRY LOW NOX BURNER		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	PSD-NM-622-M-1	11/4/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	NOX	15	PPM (SEE FAC. NOTES)	DRY LOW NOX COMBUSTION		BACT-PSD
GAINESVILLE REGIONAL UTILITIES	FL	PSD-FL-212	4/11/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	NOX	15	PPM AT 15% OXYGEN	DRY LOW NOX BURNERS GE FRAME UNIT, CAN ANNULAR COMBUSTORS		BACT-PSD
TIGER BAY LP	FL	PSD-FL-190	5/17/93	TURBINE, GAS	1614.8 MMBTU/H	NOX	15	PPM @ 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD
KALAMAZOO POWER LIMITED	MI	1234-90	12/3/91	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1805.9 MMBTU/H	NOX	15	PPMV	DRY LOW NOX TURBINES		BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	869 MMBTU/H	NOX	15	PPM @ 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD

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KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	367 MMBTU/H	NOX	15	PPM @ 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD
ORANGE COGENERATION LP	FL	PSD-FL-206	12/30/93	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	NOX	15	PPM @ 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	NOX	15	PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR		BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	PA	06-328-001	4/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	NOX	21	LB/HR	SCR WITH LOW NOX COMBUSTORS	47	BACT-OTHER
PHOENIX POWER PARTNERS	CO	92WEI357	5/11/93	TURBINE (NATURAL GAS)	311 MMBTU/HR	NOX	22	PPM @ 15% O2	DRY LOW NOX COMBUSTION		BACT-OTHER
MEAD COATED BOARD, INC.	AL	211-0004	3/12/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	NOX	25	PPMVD@ 15% O2 (GAS)	FUEL OIL SULFUR CONTENT <=0.05% BY WEIGHT DRY LOW NOX COMBUSTOR DESIGN FIRING GAS AND DRY LOW NOX COMBUSTOR WITH WATER INJECTION FIRING OIL		BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	NOX	25	PPM GAS	STEAM INJECTION		BACT-OTHER
NORTHERN CALIFORNIA POWER AGENCY	CA	N-583-1-1	10/2/97	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	NOX	25	PPMVD @ 15% O2	DRY LOW NOX BURNERS		LAER
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	GE LM-5000 GAS TURBINE	550 MMBTU/HR	NOX	25	PPM, 47 LB/HR	STEAM INJECTION, FUEL SPEC: NATURAL GAS ONLY	80	BACT
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	GENERATOR, GAS TURBINE	1313 MM BTU/HR	NOX	25	PPMV CORR. TO 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	NOX	25	PPMV-CORR. TO 15%O2	CONTROL NOX USING STEAM INJECTION		BACT-PSD
BUCKNELL UNIVERSITY	PA	60-0001A	11/26/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	NOX	25	PPMV@15%O2	SOLONOX BURNER: LOW NOX BURNER		BACT-OTHER
BRUSH COGENERATION PARTNERSHIP	CO	91MR934I		TURBINE	350 MMBTU/H	NOX	25	PPM @ 15% O2	DRY LOW NOX BURNER	74	BACT-PSD
CIMARRON CHEMICAL	CO	90WE438	3/25/91	TURBINE #1, GE FRAME 6	33 MW	NOX	25	PPM @ 15% O2	WATER INJECTION		OTHER
PEABODY MUNICIPAL LIGHT PLANT	MA	MBR-89-COM-032	11/30/89	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	NOX	25	PPM @ 15% O2	WATER INJECTION		BACT-OTHER
GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	GA	4911-076-11348	5/13/94	TURBINE, COMBUSTION, NATURAL GAS	80 MW	NOX	25	PPM	WATER INJECTION, FUEL SPEC: NATURAL GAS		BACT-PSD
FLORIDA GAS TRANSMISSION	FL	FL-PSD-202	9/27/93	TURBINE, GAS	131.59 MMBTU/H	NOX	25	PPM @ 15% O2	DRY LOW NOX COMBUSTOR		BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10941	7/28/92	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	NOX	25	PPM @ 15% O2	MAXIMUM WATER INJECTION		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	9/WE667(1-5)	2/19/92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	NOX	25	PPM @ 15% O2	DRY LOW NOX TECH.		BACT-PSD
CHARLES LARSEN POWER PLANT	FL	PSD-FL-166	7/25/91	TURBINE, GAS, 1 EACH	80 MW	NOX	25	PPM @ 15% O2	WET INJECTION		BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	TURBINE, GAS, 2 EACH	42 MW	NOX	25	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, GAS, 4 EACH	400 MW	NOX	25	PPM @ 15% O2	LOW NOX COMBUSTORS		BACT-PSD

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INTERNATIONAL PAPER	LA	PSD-LA-93(M-3)	2/24/94	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	NOX	25	PPMV 15% O2 TURBINE	DRY LOW NOX COMBUSTOR/COMBUSTION CONTROL		BACT
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	1032 MMBTU/H, NAT GAS	NOX	25	PPM @ 15% O2	MAX WATER INJECTION		BACT-PSD
NORTHERN CONSOLIDATED POWER	PA	25-328-001	5/3/91	TURBINES, GAS, 2	34.6 KW EACH	NOX	25	PPM @ 15% O2	STEAM INJECTION/+SCR IN 1997	85	OTHER
SOUTHERN CALIFORNIA GAS COMPANY	CA	S-1792-5-3	5/14/97	VARIABLE LOAD NATURAL GAS FIRED TURBINE COMPRESSOR	50.1 MMBTU/HR	NOX	25	PPMVD @ 15% O2	DRY LOW NOX COMBUSTOR		LAER
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	STACK (TURBINE AND DUCT BURNER)	715 MMBTU/HR	NOX	26	PPM, 69 LB/HR	NO CONTROLS FOR NOX ON STACK *SEE TURBINE NOX DATA		BACT-OTHER
ENRON LOUISIANA ENERGY COMPANY	LA	PSD-LA-569	8/5/91	TURBINE, GAS, 2	39.1 MMBTU/H	NOX	40	PPM @ 15% O2	H2O INJECT 0.67 LB/LB	71	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, CG, 4 EACH	400 MW	NOX	42	PPM @ 15% O2	LOW NOX COMBUSTORS		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	NOX	42	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	PSD-FL-173	11/5/91	TURBINE, GAS, 4 EACH	35 MW	NOX	42	PPM @ 15% O2	WET INJECTION	70	BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	NOX	42	PPM @ 15% O2	DRY LOW NOX COMBUSTOR	51	BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	NOX	42	PPM @ 15% O2	DRY LOW NOX COMBUSTOR	51	BACT-PSD
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	PSD-NM-340M2	10/29/93	TURBINE, GAS-FIRED	11257 HP	NOX	42	PPM @ 15% O2	SOLONOX COMBUSTOR, DRY LOW NOX TECHNOLOGY	66	BACT-PSD
PACIFIC GAS TRANSMITION	OR	16-0026	11/3/89	TURBINE, NAT. GAS	14600 HP	NOX	42	PPM @ 15% O2	LOW NOX BURNERS	75	BACT-PSD
EL PASO NATURAL GAS	AZ		10/18/91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	NOX	42	PPM @ 15% O2	DRY LOW NOX COMBUSTOR	80	BACT-PSD
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	NOX	42	PPM @ 15% O2	WATER INJECTION	66	BACT-PSD
SOUTHERN NATURAL GAS COMPANY-SELMA COMPRESSOR STAT	AL	104-0021-X001 AND -X002	12/4/96	9160 HP GE MS3002G NATURAL GAS FIRED TURBINE		NOX	53	LB/HR			BACT-PSD
PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN)	PA	66-0001	5/31/95	TURBINE, NATURAL GAS	580 MMBTU/HR	NOX	55	PPM @ 15% O2	STEAM INJECTION	75	RACT
KEY WEST CITY ELECTRIC SYSTEM	FL	AC44-245399 / PSD-FL-210	9/28/95	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	NOX	75	PPM @ 15% O2	WATER INJECTION		BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	NOX	84.9	PPM @ 15% O2	LEAN BURN		NSPS
EL PASO NATURAL GAS	AZ		10/25/91	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	NOX	85.1	PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX		NSPS
ALGONQUIN GAS TRANSMISSION CO.	RI	1126-1127	7/31/91	TURBINE, GAS, 2	49 MMBTU/H	NOX	100	PPM @ 15% O2	LOW NOX COMBUSTION		BACT-OTHER
SOUTHERN NATURAL GAS COMPANY	MS	1300-00031	12/17/96	TURBINE, NATURAL GAS-FIRED	9160 HORSEPOWER	NOX	110	PPMV @ 15% O2, DRY	PROPER TURBINE DESIGN AND OPERATION		BACT-PSD

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DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	NOX	119	LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION		BACT-PSD
WEST CAMPUS COGENERATION COMPANY	TX	23962/PSD-TX-837	5/2/94	GAS TURBINES	75.3 MW (TOTAL POWER)	NOX	200	TPY	INTERNAL COMBUSTION CONTROLS		BACT-PSD
EL PASO NATURAL GAS	AZ		10/18/91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	NOX	225	PPM @ 15% O2	LEAN BURN		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	NOX	287	LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION		BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	NOX	308	LBS/HR	WATER INJECTION		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	NOX		SEE FACILITY NOTES	DRY LOW NOX COMBUSTION		BACT-PSD
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	DUCT BURNER	450 MM BTU/HR	NOX		USE LOW NOX BURNERS	LOW NOX BURNERS		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	972 MMBTU/H, #2 OIL	NOX		SEE NOTES	MAX WATER INJECTION		BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00926/00001-9	9/1/92	TURBINE, COMBUSTION GAS (150 MW)	1146 MMBTU/HR (GAS)*	NOX (FROM GAS)	9	PPM	DRY LOW NOX		BACT-OTHER
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	NOX, GAS	60	LB/HR	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR).	72	BACT-PSD
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL (SEE NOTES)	4/1/91	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	PM	0.0023	LB/MMBTU	TURBINE DESIGN		BACT-OTHER
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	RI-PSD-4	4/13/92	TURBINE, GAS AND DUCT BURNER	1360 MMBTU/H EACH	PM	0.005	LB/MMBTU, GAS			BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	DUCT BURNER, GAS	150 MMBTU/H	PM	0.006	LB/MMBTU	FUEL SPEC: LIMITED TO NATURAL GAS		BACT-PSD
CHARLES LARSEN POWER PLANT	FL	PSD-FL-166	7/25/91	TURBINE, GAS, 1 EACH	80 MW	PM	0.006	LB/MMBTU	COMBUSTION CONTROL		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	1032 MMBTU/H, NAT GAS	PM	0.006	LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10941	7/28/92	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	PM	0.0064	LB/M BTU	FUEL SPEC: CLEAN BURNING FUELS		BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-176	11/20/91	TURBINE, GAS, 2 EACH	42 MW	PM	0.0065	LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL		BACT-PSD
TIGER BAY LP	FL	PSD-FL-190	5/17/93	DUCT BURNER, GAS	100 MMBTU/H	PM	0.01	LM/MMBTU	GOOD COMBUSTION PRACTICES		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	972 MMBTU/H, #2 OIL	PM	0.012	LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	PM	0.0136	LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-PSD
CNG TRANSMISSION	OH	Jan-70	8/12/92	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	PM	0.035	LB/MMBTU	FUEL SPEC: USE OF NATURAL GAS		OTHER
NORTHWEST PIPELINE CORPORATION	CO	91LP792(1-2) MOD. #1	5/29/92	BURNERS, DUCT, COEN	29 MMBTU/HR PER BURNER	PM	0.4	LB/HR			OTHER

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MEAD COATED BOARD, INC.	AL	211-0004	3/12/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	PM	2.5	LBS/HR (GAS)	PRIMARY FUEL IS NATURAL GAS WITH BACKUP FUEL AS DISTILLATE OIL. EFFICIENT OPERATION OF THE COM- BUSTION TURBINE		BACT-PSD
ORANGE COGENERATION LP	FL	PSD-FL-206	12/30/93	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	PM	5	LB/H	GOOD COMBUSTION		BACT-PSD
LORDSBURG L.P.	NM	PSD-NM-1975	6/18/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	PM	5.3	LBS/HR	HIGH COMBUSTION EFFICIENCY USE OF NO.2 LOW SULFUR FUEL OIL (LESS THAN 0.05% BY WT.)		BACT-PSD
GAINESVILLE REGIONAL UTILITIES	FL	PSD-FL-212	4/11/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	PM	7	LB/HR AT 20 F	FUEL SPEC: LOW SULFUR FUELS		BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	869 MMBTU/H	PM	7	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	PA	06-328-001	4/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	PM	8	LB/HR			BACT-OTHER
TIGER BAY LP	FL	PSD-FL-190	5/17/93	TURBINE, GAS	1614.8 MMBTU/H	PM	9	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	367 MMBTU/H	PM	9	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	PM	9	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
BRUSH COGENERATION PARTNERSHIP	CO	91MR934I		TURBINE	350 MMBTU/H	PM	9.9	T/YR			OTHER
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	PM	12.4	T/YR			OTHER
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	PM	15.4	LB/H	COMBUSTION CONTROL		BACT-PSD
MID-GEORGIA COGEN.	GA	4911-076-11753	4/3/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	PM	18	LB/HR	CLEAN FUEL		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, GAS, 4 EACH	400 MW	PM	18	LB/H	COMBUSTION CONTROL		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, CG, 4 EACH	400 MW	PM	19	LB/H	COMBUSTION CONTROL		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	9/WE667(1-5)	2/19/92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	PM	25.8	LB/H	FUEL SPEC: NATURAL GAS FIRED		OTHER
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	PM	45	LBS/HR	FUEL SPEC: LOW ASH CONTENT FUELS		BACT-PSD
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	STACK (TURBINE AND DUCT BURNER)	715 MMBTU/HR	PM,PM10	0.033	LB/MMBTU, 25 LB/HR	NO CONTROLS		BACT-OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	BURNERS, DUCT (2)	553 MMBTU/HR EACH	PM/PM10	0.003	LB/MMBTU	COMBUSTION CONTROLS		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	PM/PM10	0.004	LB/MMBTU, GAS	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	PM/PM10	0.004	LB/MMBTU GAS (BASE)	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	PM/PM10	0.0062	LB/MMBTU	COMBUSTION CONTROLS		BACT-OTHER

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KAMINE/BESICORP CORNING L.P.	NY	8-4638-00022/01-0	11/5/92	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	PM/PM10	0.008	LB/MMBTU	COMBUSTION CONTROL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNER	123 MMBTU/HR	PM/PM10	0.014	LB/MMBTU, GAS	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNERS (2)	206 MMBTU/HR (EACH)	PM/PM10	0.014	LB/MMBTU, GAS	COMBUSTION CONTROLS AND FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
KAMINE/BESICORP CORNING L.P.	NY	8-4638-00022/01-0	11/5/92	BURNER, DUCT	90 MMBTU/HR	PM/PM10	0.05	LB/MMBTU	COMBUSTION CONTROL		BACT-OTHER
PORTSIDE ENERGY CORP.	IN	CP 127 5260	5/13/96	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	PM/PM10	5	LBS/HR			BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	PM10	0.006	LB/MMBTU	TURBINE DESIGN		BACT-PSD
TEMPO PLASTICS	CA	S-995-5-0	12/31/96	GAS TURBINE COGENERATION UNIT		PM10	0.012	LB/MMBTU	LUBE OIL VENT COALESCER. OPACITY LIMIT APPLIES TO LUBE OIL VENTS.		LAER
NEVADA COGENERATION ASSOCIATES #2	NV	A391	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	PM10	3	LBS/HR	FUEL SPEC: BURN NATURAL GAS		BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	A360	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	PM10	3	LBS/HR	FUEL SPEC: BURN NATURAL GAS		BACT-PSD
BMW MANUFACTURING CORPORATION	SC	2060-0230-CA THROUGH CR	1/7/94	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5 MM BTU/HR TURBINES	PM10	3.79	TPY	EACH OF THE 2 BOILER-TURBINE USE A COMMON STACK		BACT-PSD
NORTHERN CALIFORNIA POWER AGENCY	CA	N-583-1-1	10/2/97	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	PM10	4.3	LB/DAY	NATURAL GAS, AIR INTAKE COOLER, VENTING THE LUBE OIL VENT INTO THE EXHAUST STREAM OF THE TURBINE FOR OXIDATION OF THE SMOKE		LAER
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	PM10	5	LB/HR	COMBUSTION CONTROL		BACT-PSD
BRUSH COGENERATION PARTNERSHIP	CO	91MR934I		TURBINE	350 MMBTU/H	PM10	9.9	T/YR			OTHER
SOUTHERN NATURAL GAS	AL	412-0013-X001 AND -X002	3/4/98	2-9160 HP GE MODEL MS3002G NATURAL GAS TURBINES	9160 HP	PM10	10.95	TPY	FUEL SPEC: NATURAL GAS		BACT-PSD
SOUTHERN NATURAL GAS	AL	206-0021-X001 AND -X002	3/2/98	9160 HP GE MODEL M53002G NATURAL GAS FIRED TURBINE	9160 HP	PM10	10.95	TPY	FUEL SPEC: NATURAL GAS		BACT-PSD
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	PM10	12.4	T/YR			OTHER
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	DUCT BURNER	710 MM BTU/HR	PM10	18.3	LB/HRCOMMON VENT	NO ADD-ON CONTROL CLEAN FUEL		BACT-PSD
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	GENERATOR, GAS TURBINE	1313 MM BTU/HR	PM10	18.3	LB/HR	NO CONTROL CLEAN FUEL		BACT-PSD
PHOENIX POWER PARTNERS	CO	92WEI357	5/11/93	GENERATOR, STEAM, W/ DUCT BURNER	50 MMBTU/HR	PM10	20.2	TPY	FUEL SPEC: NATURAL GAS COMBUSTION		BACT-OTHER
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	A533	9/18/92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	PM10	30.6	TPY (EACH TURBINE)	PRECISION CONTROL FOR THE COMBUSTOR		BACT-PSD
WEST CAMPUS COGENERATION COMPANY	TX	23962/PSD-TX-837	5/2/94	GAS TURBINES	75.3 MW (TOTAL POWER)	PM10	52	TPY	INTERNAL COMBUSTION CONTROLS		BACT

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GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	PM10	92	TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATION		BACT-PSD
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	DUCT BURNER	450 MM BTU/HR	PM10	600	MM BTU/HR CAP FOR 3	GOOD COMBUSTION PRACTICE AND PROPER OPERATION		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	PSD-NM-622-M-1	11/4/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	PM10		SEE P2	GOOD COMBUSTION PRACTICES		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	PM10					BACT-PSD
MILAGRO, WILLIAMS FIELD SERVICE	NM	PSD-NM-859-M-4		TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	PM10		SEE P2 DESC.	COMBUSTION AIR FILTERS, GOOD COMBUSTION PRACTICE AND MAINTENANCE		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	PM10, COOLING TOWER	0.0015	% OF FLOW	TWO STAGE MIST ELIMINATOR TO RESTRICT DRIFT.		BACT-OTHER
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	PM10, GAS	12	LB/HR	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GOOD COMBUSTION PRACTICES. FUEL SPEC: USE OF NG/LPG.		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	PM10, OIL	59	LB/HR	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GOOD COMBUSTION PRACTICES. FUEL SPEC: USE OF NG/LPG.		BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	SO2	0.0026	LB/MMBTU	FUEL SPEC: USE OF NATURAL GAS		BACT-PSD
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL (SEE NOTES)	4/1/91	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	SO2	0.0069	LB/MMBTU	FUEL SPEC: NAT GAS/LOW SULFUR NO.2 OIL		BACT-OTHER
NORTHWEST PIPELINE CORPORATION	CO	91LP792(1-2) MOD. #1	5/29/92	BURNERS, DUCT, COEN	29 MMBTU/HR PER BURNER	SO2	0.03	LB/HR			OTHER
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, CG, 4 EACH	400 MW	SO2	0.0834	LB/H	FUEL SPEC: COAL DERIVED GAS		BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	SO2	0.2	% SULFUR OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	SO2	0.2	% SULFUR OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNER	123 MMBTU/HR	SO2	0.2	% SULFUR OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/92	DUCT BURNERS (2)	206 MMBTU/HR (EACH)	SO2	0.2	% SULFUR OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00926/00001-9	9/1/92	TURBINE, COMBUSTION GAS (150 MW)	1146 MMBTU/HR (GAS)*	SO2	0.2	% SULFUR OIL	FUEL SPEC: LOW SULFUR OIL		BACT-OTHER
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	972 MMBTU/H, #2 OIL	SO2	0.5	% S MAX	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	SO2	0.7	LB/HR	COMBUSTION CONTROL		BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
PHOENIX POWER PARTNERS	CO	92WEI357	5/11/93	GENERATOR, STEAM, W/ DUCT BURNER	50 MMBTU/HR	SO2	0.95	TPY	FUEL SPEC: NATURAL GAS COMBUSTION		OTHER
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	SO2	0.99	LB/H	FUEL SPEC: LOW SULFUR IN NATURAL GAS		BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	A391	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW POWER OUTPUT	SO2	2.1	LB/HR	FUEL SPEC: USE OF LOW-SULFUR OIL AS STANDBY FUEL		BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	A360	1/17/91	COMBINED-CYCLE POWER GENERATION	85 MW TOTAL OUTPUT	SO2	2.1	LBS/HR	FUEL SPEC: USE OF LOW SULFUR OIL AS THE STAND-BY FUEL		BACT-PSD
WEST CAMPUS COGENERATION COMPANY	TX	23962/PSD-TX-837	5/2/94	GAS TURBINES	75.3 MW (TOTAL POWER)	SO2	2.8	TPY	INTERNAL COMBUSTION CONTROLS		BACT
LORDSBURG L.P.	NM	PSD-NM-1975	6/18/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	SO2	2.8	LBS/HR	USE OF SWEET NATURAL GAS AND NO.2 DIESEL FUEL WITH LESS THAN 0.05% BY WT. OF SULFUR		BACT-PSD
BRUSH COGENERATION PARTNERSHIP	CO	91MR9341		TURBINE	350 MMBTU/H	SO2	3.2	T/YR			OTHER
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	SO2	3.2	T/YR			OTHER
FLEETWOOD COGENERATION ASSOCIATES	PA	06-328-001	4/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	SO2	11.3	LB/HR	FUEL SPEC: 0.1 % SULFUR IN FUEL		BACT-OTHER
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	A533	9/18/92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	SO2	27.1	TPY (EACH TURBINE)	FUEL SPEC: S IN #2 DISTILLATE LIMITED TO 0.05%		BACT-PSD
GAINESVILLE REGIONAL UTILITIES	FL	PSD-FL-212	4/11/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	SO2	29	LB/HR AT 20 F (GAS)	FUEL SPEC: LOW SULFUR OIL BACKUP FUEL AND NAT GAS PRIMARY 0.05% S		BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	SO2	40	LB/H	FUEL SPEC: LOW SULFUR IN NATURAL GAS		BACT-PSD
GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	GA	4911-076-11348	5/13/94	TURBINE, COMBUSTION, NATURAL GAS	80 MW	SO2	56	PPM	FUEL SPEC: LOW SULFUR FUEL (.3% AVG) FUEL 0.1		BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE, 140 MW OIL FIRED ELECTRIC	140 MW	SO2	87	LB/HR	FUEL SPEC: LOW SULFUR OIL (0.05%)	75	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, GAS, 4 EACH	400 MW	SO2	91.5	LB/H	FUEL SPEC: NATURAL GAS AS FUEL		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	SO2	240.7	LB/HR	FUEL SPEC: 0.2% SULFUR FUEL OIL		BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	SO2	630	LBS/HR	FUEL SPEC: LOW SULFUR CONTENT FUELS		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	PSD-NM-622-M-1	11/4/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	SO2		SEE P2	SWEET PIPELINE NATURAL GAS		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	SO2		SEE FACILITY NOTES	SWEET PIPELINE NATURAL GAS		BACT-PSD
CHARLES LARSEN POWER PLANT	FL	PSD-FL-166	7/25/91	TURBINE, GAS, 1 EACH	80 MW	SO2			FUEL SPEC: LIMIT FUEL SULFUR CONTENT		BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	SO2			FUEL SPEC: NATURAL GAS AS FUEL		BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	NY	7-3556-00040-00007-9	11/24/92	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2133 MMBTU/HR (EACH)	SO2			FUEL SPEC: USE OF NATURAL GAS		BACT-OTHER

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	SO2, GAS		NEGLIGIBLE	FUEL SPEC: LNG/LPG AS PRIMARY FUEL, 0.04% SULFUR NO. 2 OIL AS BACKUP FUEL.		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	SO2, OIL	70.5	LB/HR	FUEL SPEC: LNG/LPG AS PRIMARY FUEL, 0.04% SULFUR NO. 2 OIL AS BACKUP FUEL.		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	9/WE667(1-5)	2/19/92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	SOX	1.5	LB/H			OTHER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	TSP	0.006	LB/MMBTU	TURBINE DESIGN		OTHER
MID-GEORGIA COGEN.	GA	4911-076-11753	4/3/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	VE	10	% OPACITY	COMPLETE COMBUSTION		BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10941	7/28/92	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	VE	10	% OPACITY	FUEL SPEC: CLEAN BURNING FUELS		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	1032 MMBTU/H, NAT GAS	VE	10	% OPACITY	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	972 MMBTU/H, #2 OIL	VE	10	% OPACITY	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	VE	20	% OPACITY	GOOD COMBUSTION PRACTICES		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	VE	20	% OPACITY	COMBUSTION CONTROL		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	VE	20	% OPACITY	COMBUSTION CONTROL		BACT-PSD
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	BURNERS, DUCT (2)	553 MMBTU/HR EACH	VOC	0.0011	LB/MMBTU	OXIDATION CATALYST		BACT-OTHER
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	1032 MMBTU/H, NAT GAS	VOC	0.003	LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-8529	2/12/92	TURBINES, 8	972 MMBTU/H, #2 OIL	VOC	0.0042	LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL		BACT-PSD
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-9	7/31/92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	VOC	0.0045	LB/MMBTU	OXIDATION CATALYST		BACT-OTHER
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL (SEE NOTES)	4/1/91	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	VOC	0.0046	LB/MMBTU	TURBINE DESIGN		OTHER
ALGONQUIN GAS TRANSMISSION CO.	RI	1126-1127	7/31/91	TURBINE, GAS, 2	49 MMBTU/H	VOC	0.016	LB/MMBTU	GOOD COMBUSTION PRACTICES		BACT-OTHER
CNG TRANSMISSION	OH	Jan-70	8/12/92	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	VOC	0.1	G/HP-HR	FUEL SPEC: USE OF NATURAL GAS		OTHER
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	2 GAS-FIRED GENERATOR ENGINES	385 HORSEPOWER	VOC	0.4	LBS/HR	GOOD COMBUSTION		BACT
SNYDER OIL CORPORATION-RIVERTON DOME GAS PLANT	WY	NONE	7/5/94	1 GAS-FIRED GENERATOR ENGINE	577 HORSEPOWER	VOC	0.6	LBS/HR	GOOD COMBUSTION		BACT
FLORIDA POWER AND LIGHT	FL	PSD-FL-145	3/14/91	TURBINE, GAS, 4 EACH	240 MW	VOC	1	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
NORTHWEST PIPELINE CORPORATION	CO	91LP792(1-2) MOD. #1	5/29/92	BURNERS, DUCT, COEN	MMBTU/HR 29 PER BURNER	VOC	1.6	LB/HR			OTHER
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, GAS, 4 EACH	400 MW	VOC	1.6	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313 MM BTU/HR	VOC	2	LB/HR	COMBUSTION CONTROL		BACT-PSD
INTERNATIONAL PAPER	LA	PSD-LA-93(M-3)	2/24/94	TURBINE/HRSG, GAS COGEN	MM BTU/HR 338 TURBINE	VOC	3.6	LB/HR COMBINED	COMBUSTION CONTROLS, FUEL SELECTION		BACT
BLUE MOUNTAIN POWER, LP	PA	09-328-009	7/31/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	VOC	4	PPM @ 15% O2	OXIDATION CATALYST WHEN FIRING NO. 2 OIL EMISSION LIMIT = 4.4 PPMVD @ 15% O2. @ 75% LOAD ALTERNATE GAS LIMIT 7.6 PPM	12	LAER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-5231 TO 01-92-5261	6/9/93	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	MMBTU/HR 617 (EACH)	VOC	4	PPMDV	TURBINE DESIGN		BACT-PSD
FLEETWOOD COGENERATION ASSOCIATES	PA	06-328-001	4/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	VOC	4.4	LB/HR	GOOD COMBUSTION PRACTICES		BACT-OTHER
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247 MM BTU/HR	VOC	5	LB/HR	COMBUSTION CONTROL		BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	RI-PSD-4	4/13/92	TURBINE, GAS AND DUCT BURNER	MMBTU/H 1360 EACH	VOC	5	PPM @ 15% O2			BACT-PSD
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	STACK (TURBINE AND DUCT BURNER)	715 MMBTU/HR	VOC	5.2	PPM, 2.8 LB/HR	NO CONTROLS		BACT-OTHER
MID-GEORGIA COGEN.	GA	4911-076-11753	4/3/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	VOC	6	PPMVD	COMPLETE COMBUSTION		BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/92	TURBINE,GAS	1214 MMBTU/H	VOC	6	LB/H	GOOD COMBUSTION PRACTICES		BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	PSD-FL-173	11/5/91	TURBINE, GAS, 4 EACH	35 MW	VOC	7	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	VOC	7	PPMVW	GOOD COMBUSTION PRACTICES		BACT-PSD
NORTHERN CALIFORNIA POWER AGENCY	CA	N-583-1-1	10/2/97	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	VOC	8	LB/HR	NATURAL GAS AS PRIMARY FUEL		LAER
FLORIDA POWER AND LIGHT	FL	PSD-FL-146	6/5/91	TURBINE, CG, 4 EACH	400 MW	VOC	9	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	VOC	10	LBS/HR	GOOD COMBUSTION PRACTICES		BACT-PSD
ORANGE COGENERATION LP	FL	PSD-FL-206	12/30/93	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	VOC	10	PPMVD	GOOD COMBUSTION		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	9/WE667(1-5)	2/19/92	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	VOC	16.7	LB/H			OTHER
PHOENIX POWER PARTNERS	CO	92WEI357	5/11/93	GENERATOR, STEAM, W/ DUCT BURNER	50 MMBTU/HR	VOC	24.09	TPY	FUEL SPEC: NATURAL GAS COMBUSTION		OTHER
BUCKNELL UNIVERSITY	PA	60-0001A	11/26/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	VOC	25	PPMV@15%O2	GOOD COMBUSTION		BACT-OTHER
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	PSD-NM-340M2	10/29/93	TURBINE, GAS-FIRED	11257 HP	VOC	25	PPM @ 15% O2	COMBUSTION CONTROL		BACT-PSD

FACILITY	STATE	PERMITNUM	PERMIT DATE	PROCESS	THRUPUT	POLLUTANT	PRIME EMISSIONS	UNITS	CONTROL DESCRIPTION	PERCENT EFFIC.	BASIS
BRUSH COGENERATION PARTNERSHIP	CO	91MR934I		TURBINE	350 MMBTU/H	VOC	26.7	T/YR			OTHER
TEMPLE UNIVERSITY	PA	92310	10/2/92	ELECTRIC GENERATOR (NATURAL GAS)	1.6 MW	VOC	31	LBS/HR	LEAN BURN GAS ENGINE		BACT-OTHER
COLORADO POWER PARTNERSHIP	CO	91MR933,1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	VOC	35.2	T/YR			OTHER
WEST CAMPUS COGENERATION COMPANY	TX	23962/PSD-TX-837	5/2/94	GAS TURBINES	75.3 MW (TOTAL POWER)	VOC	38	TPY	INTERNAL COMBUSTION CONTROLS		BACT
BMW MANUFACTURING CORPORATION	SC	2060-0230-CA THROUGH CR	1/7/94	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5 MM BTU/HR TURBINES	VOC	77.86	LBS/DAY	EACH OF THE 2 BOILER-TURBINE USE A COMMON STACK		LAER
NORTHERN CONSOLIDATED POWER	PA	25-328-001	5/3/91	TURBINES, GAS, 2	34.6 KW EACH	VOC	105	PPM @ 15% O2	OXIDATION CATALYST	50	OTHER
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	PSD-NM-622-M-1	11/4/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	VOC		SEE P2	GOOD COMBUSTION PRACTICES		BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	VOC					BACT-PSD
TOYOTA MOTOR CORPORATION SVCS OF N.A.	IN	CP-051-5391-00037	8/9/96	GASOLINE STORAGE TANKS (4)	19015 GALLONS	VOC		SEE CONTROL/P2	STAGE I VAPOR RECOVERY SYSTEM & SUBMERGE FILL PIPES		BACT-PSD
TOYOTA MOTOR CORPORATION SVCS OF N.A.	IN	CP-051-5391-00037	8/9/96	GASOLINE TANK FILLING (ASSEMBLY FINAL LINE)		VOC		SEE P2	STAGE II VAPOR CONTROL		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	VOC, GAS	5	PPMDV	COMBUSTION CONTROLS.		BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	VOC, OIL	8	PPMDV	COMBUSTION CONTROL.		BACT-PSD

Attachment 5
(Dispersion Modeling Protocol)

BLACK & VEATCH LLP

MEMORANDUM

Jacksonville Electric Authority	B&V Project 60903
Brandy Branch Simple Cycle CT Project	B&V File 15.0100
Air Dispersion Modeling Protocol	November 20, 1998

To: Cleve Holladay

From: Kyle J Lucas

As discussed at the meeting held with FDEP on November 4, 1998, B&V is submitting the summarized modeling protocol regarding the Air Quality Impact Analysis (AQIA) air dispersion modeling methodology for the JEA Brandy Branch simple cycle combustion turbine project. Please review and provided any comments or FDEP acceptance of this protocol the by November 25, 1998. If you have any questions please contact me at 913-458-9062.

- Air Dispersion Model: ISCST3 (Use the latest version).

- Model Options: EPA Default and flat terrain.

- GEP & Downwash:

EPA's BPIP program will be used to determine GEP stack height and direction specific building downwash for the simple cycle stack.

- Receptor Grids:

A 10 km nested rectangular receptor grid consisting of 100 m spacing out to 1 km, 250 m spacing from 1 to 5 km, 500 m spacing from 5 to 7 km, and 1,000 m spacing from7 to 10 km. Fenceline receptors at 50 m spacing and 100 m fine grid at maximum impact locations.

- Dispersion Coefficients:

Rural: based on visual inspection of a 7.5 minute USGS topographic map of the site using the Auer method.

- Meteorological Data:

Refined level modeling sequential meteorological data will consist of surface data from Jacksonville, Florida and upper air data from Waycross, Georgia for the years 1984 to 1988.

- Source Modeling Parameters:

Worst-case hourly emissions rates and operating parameters will be used for short-term modeling impacts. Emission rates and operating parameters for annual modeling impacts will be based on annual average data.

- Modeled impacts:

It is anticipated that the maximum model predicted impacts will be less than the PSD significant impact levels (SILs) for all applicable pollutants and averaging times. If this is not the case, additional agency consultation regarding increment and ambient air quality impact analyses will be initiated.

- Class I Analysis:

A regional haze visibility study and Class I SIL analysis will be performed for Class I areas within 150 km from the proposed Facility location. These areas will consists of Okefenokee and Wolf Island Wilderness Areas.

- Toxics: A toxic modeling analysis is not required.

Attachment 6
(VISCREEN Model Output)

Visual Effects Screening Analysis for
Source: Brandy Branch
Class I Area: Okefenokee Wilderness Ar

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	51.80	LB /HR
NOx (as NO2)	1025.70	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.00	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	34.00 km
Min. Source-Class I Distance:	34.00 km
Max. Source-Class I Distance:	80.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability: 4	
Wind Speed: 3.53 m/s	

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	140.	45.4	29.	2.08	1.321	.05	-.004
SKY	140.	140.	45.4	29.	2.00	.548	.05	-.007
TERRAIN	10.	84.	34.0	84.	2.87	.437	.06	.003
TERRAIN	140.	84.	34.0	84.	2.00	.181	.06	.002

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	15.	19.9	154.	2.00	1.931	.05	-.006
SKY	140.	15.	19.9	154.	2.00	.797	.05	-.011
TERRAIN	10.	0.	1.0	168.	2.00	1.710	.05	.023
TERRAIN	140.	0.	1.0	168.	2.00	.483	.05	.020

Station ID : 13889
Years : 84 85 86 87 88
Start Date : January 1
Start Time : Midnight

RUN ID : JACKSONVILLE/INT'L ARPT

End Date : December 31
End Time : 11 PM

Frequency Distribution
(Count)

Wind Direction (Blowing From) / Stability Classes

	A	B	C	D	E	F	Total
N	19	106	240	1142	281	282	2070
NNE	13	79	211	1012	178	192	1685
NE	21	113	297	1638	304	224	2597
ENE	21	116	402	1142	234	240	2155
E	23	99	399	834	220	128	1703
ESE	23	144	432	817	167	104	1687
SE	21	146	458	1122	423	344	2514
SSE	23	138	187	560	312	406	1626
S	37	160	244	635	305	418	1799
SSW	21	120	238	594	279	344	1596
SW	40	180	395	827	410	480	2332
WSW	42	208	353	791	356	535	2285
W	44	227	395	771	363	651	2451
WNW	33	219	415	981	279	508	2435
NW	29	184	394	1131	363	493	2594
NNW	20	107	188	853	299	284	1751
Total	430	2346	5248	14850	4773	5633	43848

Frequency of Calm Winds : 10568
Average Wind Speed : 7.46 Knots

Station ID : 13889
Years : 84 85 86 87 88
Start Date : January 1
Start Time : Midnight

RUN ID : JACKSONVILLE/INT'L ARPT

End Date : December 31
End Time : 11 PM

Frequency Distribution
(Normalized)

Wind Direction (Blowing From) / Stability Classes

	A	B	C	D	E	F	Total
N	0.000433	0.002417	0.005473	0.026045	0.006409	0.006431	0.047209
NNE	0.000296	0.001802	0.004812	0.023080	0.004059	0.004379	0.038428
NE	0.000479	0.002577	0.006773	0.037356	0.006933	0.005109	0.059227
ENE	0.000479	0.002646	0.009168	0.026045	0.005337	0.005473	0.049147
E	0.000525	0.002258	0.009100	0.019020	0.005017	0.002919	0.038839
ESE	0.000525	0.003284	0.009852	0.018633	0.003809	0.002372	0.038474
SE	0.000479	0.003330	0.010445	0.025588	0.009647	0.007845	0.057334
SSE	0.000525	0.003147	0.004265	0.012771	0.007115	0.009259	0.037083
S	0.000844	0.003649	0.005565	0.014482	0.006956	0.009533	0.041028
SSW	0.000479	0.002737	0.005428	0.013547	0.006363	0.007845	0.036398
SW	0.000912	0.004105	0.009008	0.018861	0.009350	0.010947	0.053184
WSW	0.000958	0.004744	0.008051	0.018040	0.008119	0.012201	0.052112
W	0.001003	0.005177	0.009008	0.017583	0.008279	0.014847	0.055898
WNW	0.000753	0.004995	0.009465	0.022373	0.006363	0.011585	0.055533
NW	0.000661	0.004196	0.008986	0.025794	0.008279	0.011243	0.059159
NNW	0.000456	0.002440	0.004288	0.019454	0.006819	0.006477	0.039933
Total	0.009807	0.053503	0.119686	0.338670	0.108853	0.128467	

Frequency of Calm Winds : 24.10%
Average Wind Speed : 7.46 Knots

WRPLOT View 1.5 by Lakes Environmental Software Inc.
www.lakes-environmental.com

Attachment 7

(Regional Haze Calculation Spreadsheet)

JEA - Brandy Branch — Wolf Island

Regional Haze Analysis — 03/22/1999 11:40 AM — Last Revised 03/22/1999

Calculation of Extinction per year of Maximum Impact

Table 1

Background Visibility 65.0 km

Background Extinction 0.06018 1/km

	Scenario Name	Actual 24-hr Impact (ug/m^3)	Date (yr/mo/dy/hr)	x Coordinate	y Coordinate	NO2 Impact (ug/m^3)	NO3 Impact (ug/m^3)	NH4NO3 (ug/m^3)	Minimum Daily Relative Humidity (%)	Maximum Daily Relative Humidity (%)	Average Daily Relative Humidity (%)	Estimate Relative Humidity Factor	NH4NO3 Source Extinction (1/km)
	NOx												
1984	SNG1	0.180	84010624	470425.5	3465472.6	0.18000	0.24300	0.31347	29	79	54.0	1.45	0.00136
1985	SNG1	0.110	85070224	470425.5	3465472.6	0.11000	0.14850	0.19157	34	87	60.5	1.65	0.00095
1986	SNG1	0.090	86071124	470425.5	3465472.6	0.09000	0.12150	0.15674	38	82	60.0	1.60	0.00075
1987	SNG1	0.110	87090824	470425.5	3465472.6	0.11000	0.14850	0.19157	45	97	71.0	2.40	0.00138
1988	SNG1	0.100	88052324	470425.5	3465472.6	0.10000	0.13500	0.17415	32	87	59.5	1.60	0.00084

	Scenario Name	Actual 24-hr Impact (ug/m^3)	Date (yr/mo/dy/hr)	x Coordinate	y Coordinate	SO2 Impact (ug/m^3)	SO4 Impact (ug/m^3)	(NH4)2SO4 (ug/m^3)	Minimum Daily Relative Humidity (%)	Maximum Daily Relative Humidity (%)	Average Daily Relative Humidity (%)	Estimate Relative Humidity Factor	(NH4)2SO4 Source Extinction (1/km)
	SO2												
1984	SNG1	0.003	84010624	470425.5	3465472.6	0.00300	0.00450	0.00619	29	79	54.0	1.45	0.00003
1985	SNG1	0.001	85070224	470425.5	3465472.6	0.00100	0.00150	0.00206	34	87	60.5	1.65	0.00001
1986	SNG1	0.001	86071124	470425.5	3465472.6	0.00100	0.00150	0.00206	38	82	60.0	1.60	0.00001
1987	SNG1	0.002	87090824	470425.5	3465472.6	0.00200	0.00300	0.00413	45	97	71.0	2.40	0.00003
1988	SNG1	0.001	88052324	470425.5	3465472.6	0.00100	0.00150	0.00206	32	87	59.5	1.60	0.00001

	Scenario Name	Actual 24-hr Impact (ug/m^3)	x Coordinate	y Coordinate	PM Source Extinction (1/km)
	PM				
1984	SNG1	0.020	470425.5	3465472.6	0.00006
1985	SNG1	0.010	470425.5	3465472.6	0.00003
1986	SNG1	0.010	470425.5	3465472.6	0.00003
1987	SNG1	0.010	470425.5	3465472.6	0.00003
1988	SNG1	0.010	470425.5	3465472.6	0.00003

	Total Source Change in Extinction (%)	Pass/Fail 5.00% Change
1984	2.41	PASS
1985	1.64	PASS
1986	1.32	PASS
1987	2.39	PASS
1988	1.46	PASS

Jacksonville Electric Authority
Brandy Branch Facility

Construction Permit Application

May 1999

BLACK & VEATCH

Contents

Attachments

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name : Jacksonville Electric Authority		
2. Site Name : Brandy Branch Facility		
3. Facility Identification Number :		[X] Unknown
4. Facility Location : Jacksonville Electric Authority - Brandy Branch Facility Street Address or Other Locator : City : Baldwin City	County : Duval	Zip Code : 32234
5. Relocatable Facility? [ ] Yes [X] No		6. Existing Permitted Facility? [ ] Yes [X] No

Rec'd 19 May 1999
Airs ID - 0310485-001-AC
PSD-FL-267

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: Name: Walter P. Bussells Title: Managing Director and Chief Executive Officer	
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202	
3. Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: 904-665-7220 Fax: 904-665-7366	
4. Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative* of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., 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.* Signature Date 7/3/95	

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
001	Unit 1 - 170 MW Simple Cycle Combustion Turbine	NA
002	Unit 2 - 170 MW Simple Cycle Combustion Turbine	NA
003	Unit 3 - 170 MW Simple Cycle Combustion Turbine	NA
004	Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)	
005	Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)	
006	Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)	

Purpose of Application and Category

ategory I : All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, .A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., 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 :

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed :

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

Current construction permit number :

Operation permit to be revised :

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application.

Operation permit to be revised/corrected :

[ ] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit.

Operation permit to be revised :

Reason for revision :

ategory II : All Air Operation Permit Applications Subject to Processing Under Rule 2-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s) :

[ ] Renewal air operation permit under Fule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a synthetic non-Title V source.

Operation permit to be revised :

Reason for revision :

Category III : All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain :

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any :
NA

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

Current operation permit number(s) :

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

Application Processing Fee

Check one :

[X] Attached - Amount : $7500.00 [ ] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations : JEA proposes to construct three 170 MW natural gas (NG) and NO. 2 fuel oil (FO) fired simple cycle combustion turbines (SCCTs) at the new electrical generating facility located near Baldwin City, Florida. The proposed SCCTs will be used for peaking power. The SCCTs proposed from this project are General Electric PG7241 FA (GE PG7241 FA).	
2. Projected or Actual Date of Commencement of Construction :	01-Oct-1999
3. Projected Date of Completion of Construction :	01-May-2001

Professional Engineer Certification

1. Professional Engineer Name : Anthony L. Compaan Registration Number : PE-0045662	
2. Professional Engineer Mailing Address : Organization/Firm : Black & Veatch Street Address : JEA - 21 W. Church St., T-10 City : Jacksonville	State : FL Zip Code : 32202-3139
3. Professional Engineer Telephone Numbers : Telephone : (904)665-7867	Fax : (904)665-7263

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 pollutant 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 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.

Anthony Lee Compaan
Signature
(seal)

ANTHONY LEE COMPAAN
CERTIFICATE
NO 0045032
STATE OF FLORIDA
REGISTERED ENGINEER

May 7, 1999
Date

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact :	
Name :	N. Bert Gianazza, P.E.
Title :	Environmental Health & Safety Group
2. Application Contact Mailing Address :	
Organization/Firm :	Jacksonville Electric Authority
Street Address :	21 West Church Street
City :	Jacksonville
State :	FL Zip Code : 32202-3139
3. Application Contact Telephone Numbers :	
Telephone :	(904)665-6247 Fax : (904)665-7376

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility, Location, and Type

1. Facility UTM Coordinates : Zone : 17 East (km) : 408.81 North (km) : 3354.38			
2. Facility Latitude/Longitude : Latitude (DD/MM/SS) : 30 19 14 Longitude (DD/MM/SS) : 81 56 55			
3. Governmental Facility Code : 0	4. Facility Status Code : C	5. Facility Major Group SIC Code : 49	6. Facility SIC(s) : 4911
7. Facility Comment : Construction of new emission sources at a new power generating facility.			

Facility Contact

1. Name and Title of Facility Contact : N. Bert Gianazza, P.E. Environmental Health & Safety Group		
2. Facility Contact Mailing Address : Organization/Firm : Jacksonville Electric Authority Street Address : 21 West Church Street City : Jacksonville	State : FL	Zip Code : 32202-3139
3. Facility Contact Telephone Numbers : Telephone : (904)665-6247	Fax : (904)665-7376	

Facility Regulatory Classifications

1. Small Business Stationary Source?	N
2. Title V Source?	Y
3. Synthetic Non-Title V Source?	N
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	Y
5. Synthetic Minor Source of Pollutants Other than HAPs?	N
6. Major Source of Hazardous Air Pollutants (HAPs)?	N
7. Synthetic Minor Source of HAPs?	N
8. One or More Emissions Units Subject to NSPS?	Y
9. One or More Emission Units Subject to NESHAP?	N
10. Title V Source by EPA Designation?	N
11. Facility Regulatory Classifications Comment :	

B. FACILITY REGULATIONS

Rule Applicability Analysis

This facility is subject to preconstruction reivew for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.400 requires the following:
Sources subject to the Prevention of Significant Deterioration (PSD)

B. FACILITY REGULATIONS

List of Applicable Regulations

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
NOX	A
CO	A
VOC	A
SO2	A
PM	A
PM10	A
SAM	SM

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location :	Attachment A
2. Facility Plot Plan :	Attachment B
3. Process Flow Diagram(s) :	Attachment C
4. Precautions to Prevent Emissions of Unconfined Particulate Matter :	Attachment E
5. Fugitive Emissions Identification :	NA
6. Supplemental Information for Construction Permit Applica	Attachment F

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt
8. List of Equipment/Activities Regulated under
9. Alternative Methods of Operation :
10. Alternative Modes of Operation (Emissions
11. Identification of Additional Applicable
12. Compliance Assurance Monitoring Plan :
13. Risk Management Plan Verification :
14. Compliance Report and Plan :
15. Compliance Certification (Hard-copy Require

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

   [X] 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.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

   [X] 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.

Emissions Unit Information Section 1

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 1 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 001 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This emission unit will be a GE PG7241 FA combustion turbine. Unit information throughout application is based on baseload, ISO conditions (59F). Natural gas or low sulfur distillate fuel oil fired.		

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing the use of dry low NOx burner technology to control NOx emissions.	
2. Control Device or Method Code :	25

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This will be used for fuel oil firing.	
2. Control Device or Method Code :	28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	01-May-2001
2. Long-term Reserve Shutdown Date :	
3. Package Unit : Manufacturer : General Electric	Model Number : GE PG7241 FA
4. Generator Nameplate Rating : 170 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :	 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 1736	mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : The maximum heat input (MBtu/h): Natural Gas firing @ 20F, 100% load = 1,736.3 LHV Fuel Oil firing @ 20F, 100% load = 1,934.7 LHV		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :	
24 hours/day	7 days/week
52 weeks/year	8,760 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.400
Prevention of Significant Deterioration (PSD)

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-1		
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 - Type 1 emission point		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : N/A - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	90	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	999	°F
9. Actual Volumetric Flow Rate :	999999	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 408.835 North (km) : 3354.491		
14. Emission Point Comment : Exit temperature and flow rate conservatively reflect worst-case low load and natural gas operation. Temp = 1,081F Flow = 1,623,767 acfm		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning natural gas.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.87	5. Maximum Annual Rate : 7,480.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 869	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1622.9 Mbtu/h)/(1 lb/20,675 Btu)/(23.8 ft^3/lb)=1.87 Mscf/h (1.87 Mscf/h)x(4000 h/yr)=7,480 Mscf/yr (20675 Btu/lb)x(1 lb/23.8 ft^3)=868.7 Mbtu/Mscf	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning No. 2 distillate fuel oil.	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 14.79	5. Maximum Annual Rate : 11,835.10
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 131	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1934.7 Mbtu/h)/(1 lb/18550 Btu)/(gal/ 7.05 lb)=14.79 1000 gal/h (14790 gal/h)x(800 h/yr)=11835.1 1000 gal/yr (18550)x(7.05)/(1000)=130.8 Btu/1000 gal	

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			EL
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			EL
8 - SAM			NS
9 - H095			NS
10 - H021			NS
11 - H015			NS
12 - H114			NS

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 318.0000000 lb/hour 285.6000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor Units : Reference : Manufacturer's Data
7. Emissions Method Code : 0
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 79.2 lb/h Fuel Oil = 318 lb/h Potential hour of operation: Natural Gas = 4,000 h/yr Fuel Oil = 800 h/yr Potential annual emissions: [(79.2 lb/h x 4,000 h/yr) + (318 lb/h x 800 h/yr)] / (2,000 lb/ton) = 285.60 ton/yr
9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	12.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	84.80	lb/hour	169.60	tons/year
5. Method of Compliance : CEM - 30 day rolling average or acceptable alternative.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	338.00	lb/hour	135.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppm@15%O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: 40 CFR 60.334(b) Subpart GG - Standards of performance for Stationary Gas Turbines NOTE: 75 ppm@15%O2 is based on the equation in 40 CFR 60.332(a)(1)		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
65.0000000 lb/hour 122.0000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 48 lb/h
Fuel Oil = 65 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(48 lb/h x 4,000 h/yr) + (65 lb/h x 800 h/yr)] / (2,000 lb/ton) = 122.0 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	15.00	ppm		
4. Equivalent Allowable Emissions :	52.00	lb/hour	104.00	tons/year
5. Method of Compliance : Method 10				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/r operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	26.00	ppm		
4. Equivalent Allowable Emissions :	74.00	lb/hour	29.60	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **VOC**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
   3.0000000 lb/hour 6.8000000 tons/year

4. Synthetically Limited?
   [X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
   to tons/year

6. Emissions Factor Units :
   Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

   Highest hourly emissions for simple cycle operation:
   Natural Gas = 2.8 lb/h
   Fuel Oil = 3 lb/h

   Potential hour of operation:
   Natural Gas = 4,000 h/yr
   Fuel Oil = 800 h/yr

   Potential annual emissions:
   [(2.8 lb/h x 4,000 h/yr) + (3 lb/h x 800 h/yr)] / (2,000 lb/ton) = 6.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	6.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	1.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 98.2100000 lb/hour 41.4200000 tons/year
4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor Units :   Reference : Manufacturer's Data
7. Emissions Method Code : 0
8. Calculations of Emissions :   Highest hourly emissions for simple cycle operation: Natural Gas = 1.07 lb/h (0.2 gr Sulfur/100 scf)   Fuel Oil = 98.21 lb/h (0.05% Sulfur)   Potential hour of operation: Natural Gas = 4,000 h/yr   Fuel Oil = 800 h/yr   Potential annual emissions: [(1.07 lb/h x 4,000 h/yr) + (98.21 lb/h x 800 h/yr)] / (2,000 lb/ton) = 41.42 ton/yr
9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	2.28	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	104.30	lb/h		
4. Equivalent Allowable Emissions :	104.30	lb/hour	41.72	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.80 % by weight
4. Equivalent Allowable Emissions :	lb/hour tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS 40 CFR 60.334(b) Subpart GG - Standards of Performance for Stationary Gas Turbines.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
17.0000000 lb/hour 24.8000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 9.0 lb/h
Fuel Oil = 17.0 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	9.00	lb/h		
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	17.00	lb/h		
4. Equivalent Allowable Emissions :	17.00	lb/hour	6.80	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
17.0000000 lb/hour 24.8000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 9.0 lb/h
Fuel Oil = 17.0 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	9.00	lb/h		
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	17.00	lb/h		
4. Equivalent Allowable Emissions :	17.00	lb/hour	6.80	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :
2. Basis for Allowable Opacity : OTHER
3. Requested Allowable Opacity : Normal Conditions : 10 % Exceptional Conditions : 100 % Maximum Period of Excess Opacity Allowed : 6 min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity
5. Visible Emissions Comment : Two-hour rule for startup and shutdown (62-210.700)

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype :		
2. Basis for Allowable Opacity : RULE		
3. Requested Allowable Opacity :		
Normal Conditions :	20	%
Exceptional Conditions :		%
Maximum Period of Excess Opacity Allowed :		min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity.		
5. Visible Emissions Comment : RULE for VE20: 62-296.310(2) General Visibility Emission Standard		

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 2
:

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Natural gas flow monitoring will be operated pursuant to 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 4
:

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Fuel oil flow monitoring will be operated pursuant to 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 5

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :

PM :	C	SO2 :	C	NO2 :	C

4. Baseline Emissions :

PM :	0.0000	lb/hour	0.0000	tons/year
SO2 :	0.0000	lb/hour	0.0000	tons/year
NO2 :			0.0000	tons/year

5. PSD Comment :

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 1

Unit 1 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	NA
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	NA
13. Compliance Assurance Monitoring Plan :	NA

14. Acid Rain Application (Hard-copy Required) :

NA	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

   [X] 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.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

   [X] 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.

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 2 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 002 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This emission unit will be a GE PG7241 FA combustion turbine. Unit information throughout application is based on baseload, ISO conditions (59F). Natural gas or low sulfur distillate fuel oil fired.		

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing the use of dry low NOx burner technology to control NOx emissions.
2. Control Device or Method Code : 25

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This will be used for fuel oil firing.	
2. Control Device or Method Code :	28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	01-May-2001
2. Long-term Reserve Shutdown Date :	
3. Package Unit : Manufacturer : General Electric	Model Number : GE PG7241 FA
4. Generator Nameplate Rating :	170 MW
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :	 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 1736	mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : The maximum heat input (MBtu/h): Natural Gas firing @ 20F, 100% load = 1,736.3 LHV Fuel Oil firing @ 20F, 100% load = 1,934.7 LHV		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :	
24 hours/day	7 days/week
52 weeks/year	8,760 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.400
Prevention of Significant Deterioration (PSD)

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-2		
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 - Type 1 emission point		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : N/A - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	90	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	999	°F
9. Actual Volumetric Flow Rate :	999999	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 408.774	North (km) : 3354.491	
14. Emission Point Comment : Exit temperature and flow rate conservatively reflect worst-case low load and natural gas operation. Temp = 1,081F Flow = 1,623,767 acfm		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning natural gas.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.87	5. Maximum Annual Rate : 7,480.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 869	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1622.9 Mbtu/h)/(1 lb/20,675 Btu)/(23.8 ft^3/lb)=1.87 Mscf/h (1.87 Mscf/h)x(4000 h/yr)=7,480 Mscf/yr (20675 Btu/lb)x(1 lb/23.8 ft^3)=868.7 Mbtu/Mscf	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning No. 2 distillate fuel oil.	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 14.79	5. Maximum Annual Rate : 11,835.10
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 131	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1934.7 Mbtu/h)/(1 lb/18550 Btu)/(gal/ 7.05 lb)=14.79 1000 gal/h (14790 gal/h)x(800 h/yr)=11835.1 1000 gal/yr (18550)x(7.05)/(1000)=130.8 Btu/1000 gal	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			EL
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			EL
8 - SAM			NS
9 - H095			NS
10 - H021			NS
11 - H015			NS
12 - H114			NS

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
   318.0000000 lb/hour 285.6000000 tons/year

4. Synthetically Limited?
   [X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
   to tons/year

6. Emissions Factor Units :
   Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

   Highest hourly emissions for simple cycle operation:
   Natural Gas = 79.2 lb/h
   Fuel Oil = 318 lb/h

   Potential hour of operation:
   Natural Gas = 4,000 h/yr
   Fuel Oil = 800 h/yr

   Potential annual emissions:
   [(99 lb/h x 4,000 h/yr) + (318 lb/h x 800 h/yr)] / (2,000 lb/ton) = 285.6 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	12.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	84.80	lb/hour	169.60	tons/year
5. Method of Compliance : CEM - 30 day rolling average or acceptable alternative.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	338.00	lb/hour	135.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppm@15%O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: 40 CFR 60.334(b) Subpart GG - Standards of performance for Stationary Gas Turbines NOTE: 75 ppm@15%O2 is based on the equation in 40 CFR 60.332(a)(1)		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
65.0000000 lb/hour 122.0000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 48 lb/h
Fuel Oil = 65 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(48 lb/h x 4,000 h/yr) + (65 lb/h x 800 h/yr)] / (2,000 lb/ton) = 122.0 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	15.00	ppm		
4. Equivalent Allowable Emissions :	52.00	lb/hour	104.00	tons/year
5. Method of Compliance : Method 10				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/r operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	26.00	ppm		
4. Equivalent Allowable Emissions :	74.00	lb/hour	29.60	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **VOC**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
   3.0000000 lb/hour 6.8000000 tons/year

4. Synthetically Limited?
   [X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
   to tons/year

6. Emissions Factor Units :
   Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

   Highest hourly emissions for simple cycle operation:
   Natural Gas = 2.8 lb/h
   Fuel Oil = 3 lb/h

   Potential hour of operation:
   Natural Gas = 4,000 h/yr
   Fuel Oil = 800 h/yr

   Potential annual emissions:
   [(2.8 lb/h x 4,000 h/yr) + (3 lb/h x 800 h/yr)] / (2,000 lb/ton) = 6.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	6.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	1.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 98.2100000 lb/hour	41.4200000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor Reference : Manufacturer's Data	Units :
7. Emissions Method Code : 0	
8. Calculations of Emissions : Highest hourly emissions for simple cycle operation: Natural Gas = 1.07 lb/h (0.2 gr Sulfur/100 scf) Fuel Oil = 98.21 lb/h (0.05% Sulfur) Potential hour of operation: Natural Gas = 4,000 h/yr Fuel Oil = 800 h/yr Potential annual emissions: [(1.07 lb/h x 4,000 h/yr) + (98.21 lb/h x 800 h/yr)] / (2,000 lb/ton) = 41.42 ton/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	2.28	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	104.30	lb/h		
4. Equivalent Allowable Emissions :	104.30	lb/hour	41.72	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS 40 CFR 60.334(b) Subpart GG - Standards of Performance for Stationary Gas Turbines.		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 17.0000000 lb/hour 24.8000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor Units :   Reference : Manufacturer's Data
7. Emissions Method Code : 0
8. Calculations of Emissions :   Highest hourly emissions for simple cycle operation: Natural Gas = 9.0 lb/h   Fuel Oil = 17.0 lb/h   Potential hour of operation: Natural Gas = 4,000 h/yr   Fuel Oil = 800 h/yr   Potential annual emissions: [(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr
9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	9.00	lb/h		
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	17.00	lb/h		
4. Equivalent Allowable Emissions :	17.00	lb/hour	6.80	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
17.0000000 lb/hour 24.8000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 9.0 lb/h
Fuel Oil = 17.0 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	9.00	lb/h		
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	17.00 lb/h
4. Equivalent Allowable Emissions :	17.00 lb/hour 6.80 tons/year
5. Method of Compliance :	Method 9
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :	Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :		
2. Basis for Allowable Opacity : OTHER		
3. Requested Allowable Opacity :		
Normal Conditions :	10	%
Exceptional Conditions :	100	%
Maximum Period of Excess Opacity Allowed :	6	min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity		
5. Visible Emissions Comment : Two hour rule startup / shutdown 62-210.700		

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype :	
2. Basis for Allowable Opacity : RULE	
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour	
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity.	
5. Visible Emissions Comment : RULE for VE20: 62-296.310(2) General Visibility Emission Standard	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 2

:

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Natural gas flow monitoring will be operated pursuant to 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 4
:

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Fuel oil flow monitoring will be operated pursuant to 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 5

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :						
PM :	C	SO2 :	C	NO2 :	C	
4. Baseline Emissions :						
PM :	0.0000	lb/hour		0.0000	tons/year	
SO2 :	0.0000	lb/hour		0.0000	tons/year	
NO2 :				0.0000	tons/year	
5. PSD Comment :						

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 2

Unit 2 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	NA
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	NA
13. Compliance Assurance Monitoring Plan :	NA

14. Acid Rain Application (Hard-copy Required) :

NA	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

[X] 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.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

[X] 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.

Emissions Unit Information Section 3

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 3 - 170 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 003 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This emission unit will be a GE PG7241 FA combustion turbine. Unit information throughout application is based on baseload, ISO conditions (59F). Natural gas or low sulfur distillate fuel oil fired.		

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner Technology (two-stage combustor): For natural gas firing the use of dry low NOx burner technology to control NOx emissions.	
2. Control Device or Method Code :	25

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This will be used for fuel oil firing.	
2. Control Device or Method Code :	28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date : 01-May-2001	
2. Long-term Reserve Shutdown Date :	
3. Package Unit : Manufacturer : General Electric	Model Number : GE PG7241 FA
4. Generator Nameplate Rating : 170 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :	 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 1736	mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : The maximum heat input (MBtu/h): Natural Gas firing @ 20F, 100% load = 1,736.3 LHV Fuel Oil firing @ 20F, 100% load = 1,934.7 LHV		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :	
24 hours/day	7 days/week
52 weeks/year	8,760 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

This facility is subject to preconstruction review for stationary sources (Chpt. 62-212 FAC).

Rule 62-212.400
Prevention of Significant Deterioration

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-3		
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 - Type 1 emission point		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : N/A - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	90	feet
7. Exit Diameter :	18.0	feet
8. Exit Temperature :	999	°F
9. Actual Volumetric Flow Rate :	999999	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm
12. Nonstack Emission Point Height :	0	feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 408.713 North (km) : 3354.491		
14. Emission Point Comment : Exit temperature and flow rate conservatively reflect worst-case low load and natural gas operation. Temp = 1,081F Flow = 1,623,767 acfm		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning natural gas.	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.87	5. Maximum Annual Rate : 7,480.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 869	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1622.9 Mbtu/h)/(1 lb/20,675 Btu)/(23.8 ft^3/lb)=1.87 Mscf/h (1.87 Mscf/h)x(4000 h/yr)=7,480 Mscf/yr (20675 Btu/lb)x(1 lb/23.8 ft^3)=868.7 Mbtu/Mscf	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning No. 2 distillate fuel oil.	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 14.79	5. Maximum Annual Rate : 11,832.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 131	
10. Segment Comment : (heat input)/(fuel LHV)/(fuel density)=hr rate (1934.7 Mbtu/h)/(1 lb/18550 Btu)/(gal/ 7.05 lb)=14.79 1000 gal/h (14790 gal/h)x(400 h/yr)=5917.53 1000 gal/yr (18550)x(7.05)/(1000)=130.8 Btu/1000 gal	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	025	028	EL
2 - CO			EL
3 - VOC			EL
4 - SO2	030		EL
5 - PM			EL
6 - PM10			EL
7 - PB			EL
8 - SAM			NS
9 - H095			NS
10 - H021			NS
11 - H015			NS
12 - H114			NS

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
318.0000000 lb/hour 285.6000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 79.2 lb/h
Fuel Oil = 318 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(79.2 lb/h x 4,000 h/yr) + (318 lb/h x 800 h/yr)] / (2,000 lb/ton) = 285.6 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	12.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	84.80	lb/hour	169.60	tons/year
5. Method of Compliance : CEM - 30 day rolling average or acceptable alternative.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	338.00	lb/hour	135.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	75.00	ppm@15%O2
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: 40 CFR 60.334(b) Subpart GG - Standards of performance for Stationary Gas Turbines NOTE: 75 ppm@15%O2 is based on the equation in 40 CFR 60.332(a)(1)		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **CO**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
65.0000000 lb/hour 122.0000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 48 lb/h
Fuel Oil = 65 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(48 lb/h x 4,000 h/yr) + (65 lb/h x 800 h/yr)] / (2,000 lb/ton) = 122 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		15.00	ppm	
4. Equivalent Allowable Emissions :	52.00	lb/hour	104.00	tons/year
5. Method of Compliance : Method 10				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/r operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	26.00	ppm		
4. Equivalent Allowable Emissions :	74.00	lb/hour	29.60	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

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H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **VOC**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 3.0000000 lb/hour	6.8000000 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor Reference : Manufacturer's Data	Units :
7. Emissions Method Code : 0	

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 2.8 lb/h
Fuel Oil = 3 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(2.8 lb/h x 4,000 h/yr) + (3 lb/h x 800 h/yr)] / (2,000 lb/ton) = 6.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	6.00	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	ppm		
4. Equivalent Allowable Emissions :	3.00	lb/hour	1.20	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **SO2**		
2. Total Percent Efficiency of Control :	%	
3. Potential Emissions :	98.2100000 lb/hour	41.4200000 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions:	to	tons/year
6. Emissions Factor Reference : Manufacturer's Data	Units :	
7. Emissions Method Code : 0		

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 1.07 lb/h (0.2 gr Sulfur/100 scf)
Fuel Oil = 98.21 lb/h (0.05% Sulfur)

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(1.07 lb/h x 4,000 h/yr) + (98.21 lb/h x 800 h/yr)] / (2,000 lb/ton) = 41.42 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.14	lb/h		
4. Equivalent Allowable Emissions :	1.14	lb/hour	2.28	tons/year
5. Method of Compliance :				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.				

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Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER
2. Future Effective Date of Allowable Emissions :
3. Requested Allowable Emissions and Units : 104.30 lb/h
4. Equivalent Allowable Emissions : 104.30 lb/hour 41.72 tons/year
5. Method of Compliance :
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	RULE	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	0.80	% by weight
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : NSPS 40 CFR 60.334(b) Subpart GG		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: NSPS 40 CFR 60.334(b) Subpart GG - Standards of Performance for Stationary Gas Turbines.		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **PM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
17.0000000 lb/hour 24.8000000 tons/year

4. Synthetically Limited?
[X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor Units :
Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

Highest hourly emissions for simple cycle operation:
Natural Gas = 9.0 lb/h
Fuel Oil = 17.0 lb/h

Potential hour of operation:
Natural Gas = 4,000 h/yr
Fuel Oil = 800 h/yr

Potential annual emissions:
[(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	9.00	lb/h		
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER	
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units : 17.00 lb/h	
4. Equivalent Allowable Emissions : 17.00 lb/hour 6.80 tons/year	
5. Method of Compliance : Method 9	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **PM10**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
   17.0000000 lb/hour 24.8000000 tons/year

4. Synthetically Limited?
   [X] Yes [ ] No

5. Range of Estimated Fugitive/Other Emissions:
   to tons/year

6. Emissions Factor Units :
   Reference : Manufacturer's Data

7. Emissions Method Code : 0

8. Calculations of Emissions :

   Highest hourly emissions for simple cycle operation:
   Natural Gas = 9.0 lb/h
   Fuel Oil = 17.0 lb/h

   Potential hour of operation:
   Natural Gas = 4,000 h/yr
   Fuel Oil = 800 h/yr

   Potential annual emissions:
   [(9.0 lb/h x 4,000 h/yr) + (17.0 lb/h x 800 h/yr)] / (2,000 lb/ton) = 24.8 ton/yr

9. Pollutant Potential/Estimated Emissions Comment :

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Emission calculations based on manufacturer's guarantees at 59F ambient conditions.

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	9.00	lb/h		
4. Equivalent Allowable Emissions :	9.00	lb/hour	18.00	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas firing for 4,000 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	17.00	lb/h		
4. Equivalent Allowable Emissions :	17.00	lb/hour	6.80	tons/year
5. Method of Compliance : Method 9				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Fuel oil firing for 800 h/yr. Expected lb/h operating limit for forthcoming air construction. permit. Max lb/h emission rate considering all temps and loads. FRONT HALF CATCH ONLY				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :			
2. Basis for Allowable Opacity :	OTHER		
3. Requested Allowable Opacity :			
Normal Conditions :		10	%
Exceptional Conditions :		100	%
Maximum Period of Excess Opacity Allowed :		6	min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity			
5. Visible Emissions Comment : Two-hour rule. Startup / shutdown 62-210.700			

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype :
2. Basis for Allowable Opacity : RULE
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity.
5. Visible Emissions Comment : RULE for VE20: 62-296.310(2) General Visibility Emission Standard

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 2
:

1. Parameter Code : WTF	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Natural gas flow monitoring will be operated pursuant to 40 CFR 75.	

Continuous Monitoring System Continuous Monitor 4
:

1. Parameter Code : FLOW	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Fuel oil flow monitoring will be operated pursuant to 40 CFR 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Unit 3 - 170 MW Simple Cycle Combustion Turbine

Continuous Monitoring System Continuous Monitor 5

1. Parameter Code : O2	2. Pollutant(s):
3. CMS Requirement OTHER	
4. Monitor Information Manufacturer : Unknown Model Number : Unknown Serial Number : Unknown	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : CEM will be installed before operation of emission source. Required as a condition of 40 CFR 75.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :				
PM : C		SO2 : C		NO2 : C
4. Baseline Emissions :				
PM :	0.0000	lb/hour	0.0000	tons/year
SO2 :	0.0000	lb/hour	0.0000	tons/year
NO2 :			0.0000	tons/year
5. PSD Comment :				

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 3

Unit 3 - 170 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment H
2. Fuel Analysis or Specification :	Attachment I
3. Detailed Description of Control Equipment :	Attachment J
4. Description of Stack Sampling Facilities :	Attachment K
5. Compliance Test Report :	Attachment L
6. Procedures for Startup and Shutdown :	Attachment M
7. Operation and Maintenance Plan :	Attachment N
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	NA
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	NA
13. Compliance Assurance Monitoring Plan :	NA

14. Acid Rain Application (Hard-copy Required) :

NA	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

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

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

2. Single Process, Group of Processes, or Fugitive Only? 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).

[X] 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.

Emissions Unit Information Section 4

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)		
2. Emissions Unit Identification Number : 004 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [ ] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This distillate fuel oil storage tank (1,000,000 gal) is reported as an emission unit because it is subject to reporting regulations based on the emissions guidelines on the New Source Performance Standards 40 CFR 60, Subpart Kb. The tank is a vertical fixed roof design.		

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Emissions Unit Control Equipment

1. Description :
2. Control Device or Method Code :

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-4		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof. There are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below. 1.) Storage Loss: Emission resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss). 2.) Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.		
5. Discharge Type Code :	P	
6. Stack Height :	40	feet
7. Exit Diameter :	0.0	feet
8. Exit Temperature :	59	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm

12. Nonstack Emission Point Height :	40 feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 408.934 North (km) : 3354.448	
14. Emission Point Comment :	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : #2 Fuel Oil Storage	
2. Source Classification Code (SCC) : 40301019	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 1,000.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment : (1,000,000 gal stored)/(1,000 gal) = 1,000 capacity factor	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 4
Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - VOC			NS

Emissions Unit Information Section 4
Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	
4. Equivalent Allowable Emissions : lb/hour	tons/year
5. Method of Compliance : As specified in 40 CFR 60.116(a) and (b), Subpart kb.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Rule: 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :			
	PM :	SO2 :	NO2 :
4. Baseline Emissions :			
	PM :	lb/hour	tons/year
	SO2 :	lb/hour	tons/year
	NO2 :		tons/year
5. PSD Comment :			
Tank does not emit PSD increment consuming pollutants.			

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank #1 (1,000,000 gal)

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment P
2. Fuel Analysis or Specification :	NA
3. Detailed Description of Control Equipment :	NA
4. Description of Stack Sampling Facilities :	NA
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	NA
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :
11. Alterntive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

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

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

2. Single Process, Group of Processes, or Fugitive Only? 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).

[X] 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.

Emissions Unit Information Section 5

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)		
2. Emissions Unit Identification Number : 005 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [ ] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This distillate fuel oil storage tank (1,000,000 gal) is reported as an emission unit because it is subject to reporting regulations based on the emissions guidelines on the New Source Performance Standards 40 CFR 60, Subpart Kb. The tank is a vertical fixed roof design.		

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

Emissions Unit Control Equipment

1. Description :
2. Control Device or Method Code :

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-5		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof. There are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below. 1.) Storage Loss: Emission resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss). 2.) Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.		
5. Discharge Type Code :	P	
6. Stack Height :	40	feet
7. Exit Diameter :	0.0	feet
8. Exit Temperature :	59	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm

12. Nonstack Emission Point Height :	40 feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 408.934 North (km) : 3354.415	
14. Emission Point Comment :	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : #2 Fuel Oil Storage	
2. Source Classification Code (SCC) : 40301019	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 1,000.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment : (1,000,000 gal stored)/(1,000 gal) = 1,000 capacity factor	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 5
Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - VOC			NS

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM :	SO2 :	NO2 :
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		
Tank does not emit PSD increment consuming pollutants.		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 5

Distillate Fuel Oil Storage Tank #2 (1,000,000 gal)

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment P
2. Fuel Analysis or Specification :	NA
3. Detailed Description of Control Equipment :	NA
4. Description of Stack Sampling Facilities :	NA
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	NA
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :
11. Alterntive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section ___6___

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

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

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

2. Single Process, Group of Processes, or Fugitive Only? 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).

   [X] 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.

Emissions Unit Information Section 6

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)		
2. Emissions Unit Identification Number : 006 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : C	4. Acid Rain Unit? [ ] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This distillate fuel oil storage tank (1,000,000 gal) is reported as an emission unit because it is subject to reporting regulations based on the emissions guidelines on the New Source Performance Standards 40 CFR 60, Subpart Kb. The tank is a vertical fixed roof design.		

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

Emissions Unit Control Equipment

1. Description :	
2. Control Device or Method Code :	

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-6		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point)		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof. There are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below. 1.) Storage Loss: Emission resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss). 2.) Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.		
5. Discharge Type Code :	P	
6. Stack Height :	40	feet
7. Exit Diameter :	0.0	feet
8. Exit Temperature :	59	°F
9. Actual Volumetric Flow Rate :	0	acfm
10. Percent Water Vapor :	0.00	%
11. Maximum Dry Standard Flow Rate :	0	dscfm

12. Nonstack Emission Point Height :				40	feet
13. Emission Point UTM Coordinates :					
Zone : 17		East (km) :	408.910	North (km) :	3354.414
14. Emission Point Comment :					

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : #2 Fuel Oil Storage	
2. Source Classification Code (SCC) : 40301019	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 1,000.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment : (1,000,000 gal stored)/(1,000 gal) = 1,000 capacity factor	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 6
Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - VOC			NS

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM :	SO2 :	NO2 :
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		
Tank does not emit PSD increment consuming pollutants.		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 6

Distillate Fuel Oil Storage Tank #3 (1,000,000 gal)

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Attachment P
2. Fuel Analysis or Specification :	NA
3. Detailed Description of Control Equipment :	NA
4. Description of Stack Sampling Facilities :	NA
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	NA
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	Attachment F
9. Other Information Required by Rule or Statue :	NA

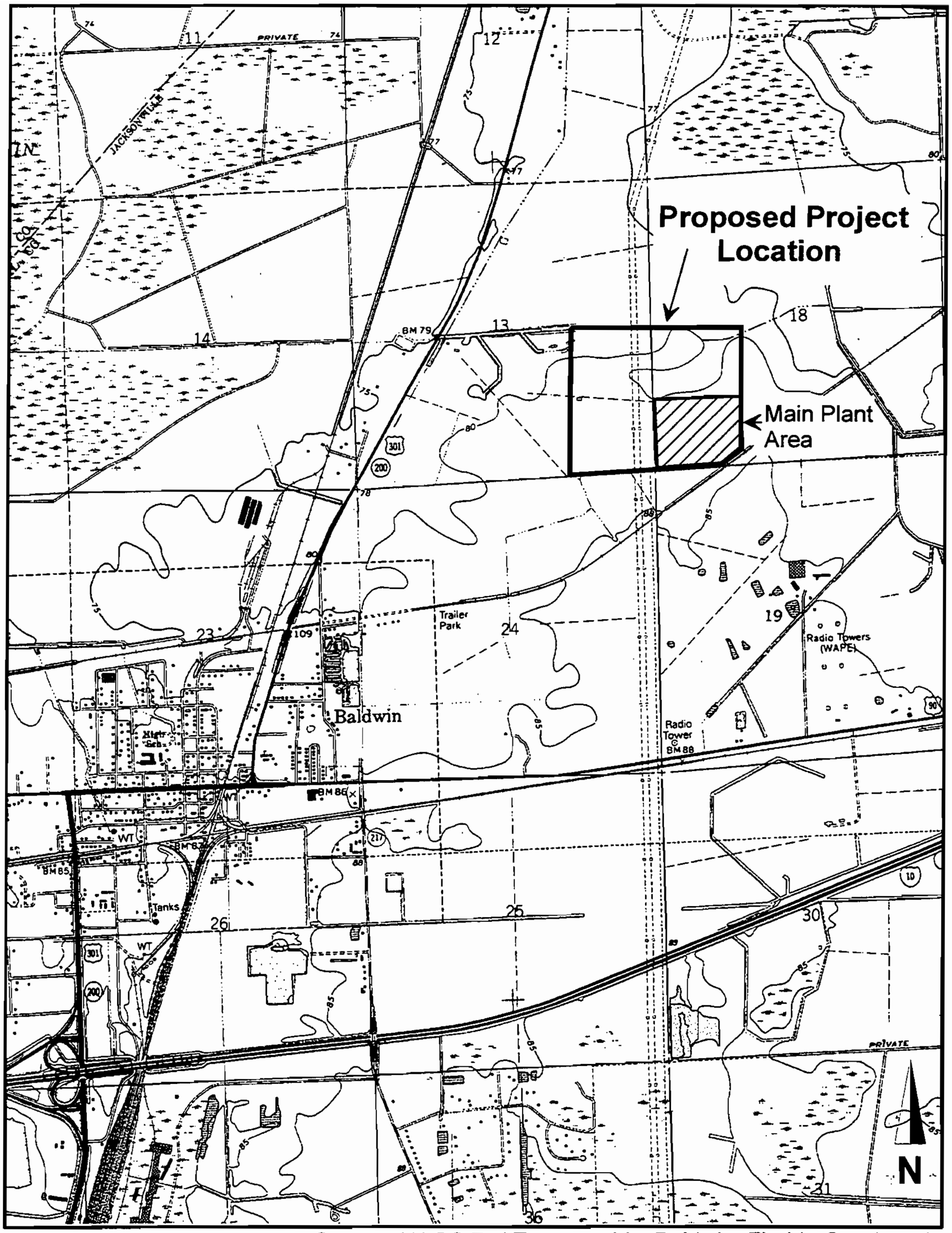
Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :
11. Alterntive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

Attachment A

Area Map Showing Facility Location

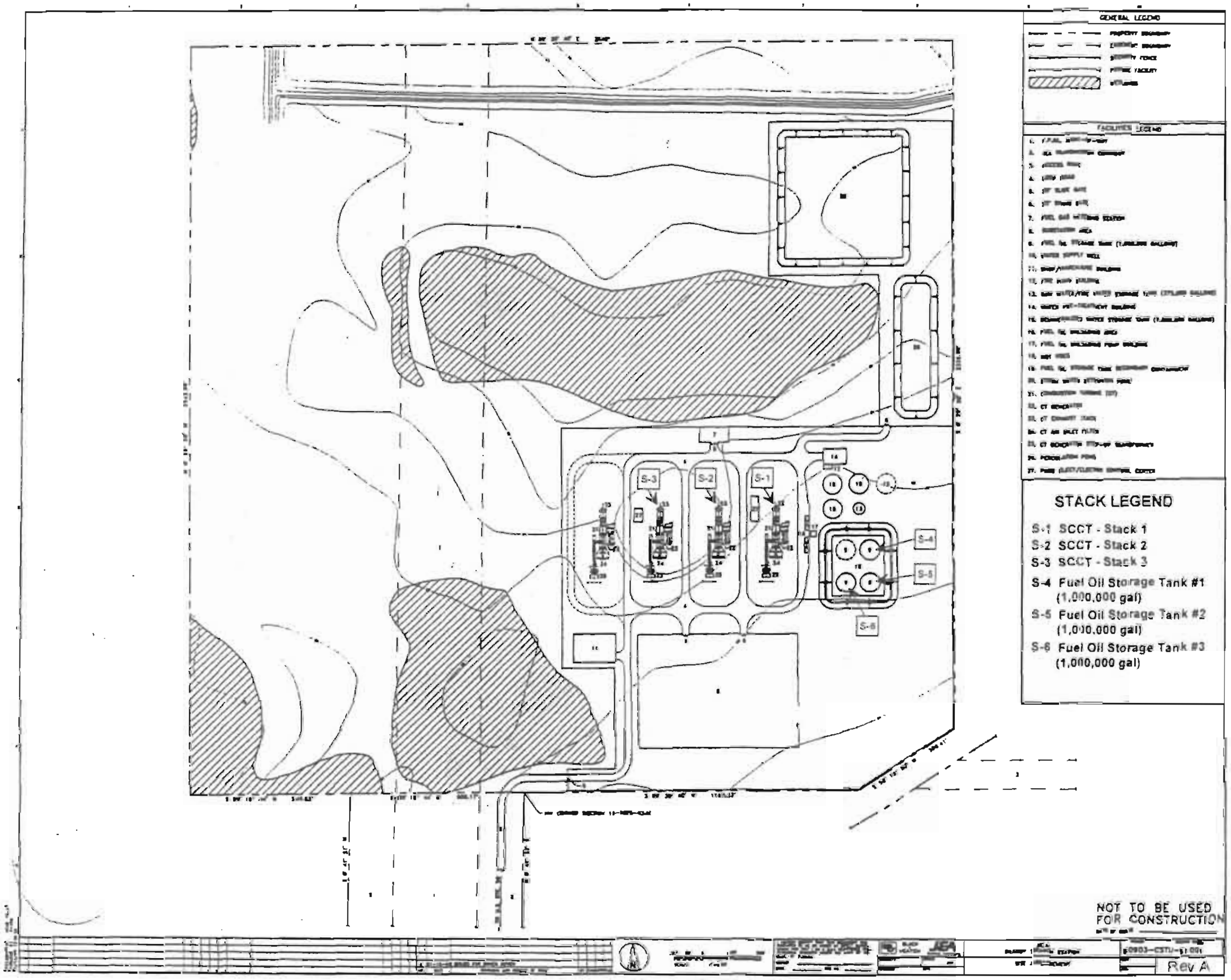


Source: USGS 7.5' Topographic, Baldwin, Florida Quadrangle

Proposed Project Location

Attachment B

Facility Plot Plan



JEASTACK.SRF

Attachment C

Process Flow Diagrams
(See individual unit process flow diagrams, Attachments H, and P)

Attachment D

Facility Applicable Requirements

Facility Applicable Requirements

Applicable Regulation	Applicable Requirement
40 CFR 60.7, Notification and recordkeeping	Any physical or operational change to an existing facility which may increase the emission of any air pollutant requires notification pursuant to this rule, postmarked 60 days before the change is commenced.
	An excess emissions and monitoring systems performance report shall be submitted semiannually. The facility shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the facility; any malfunction of the air pollution control equipment; or any period the CEMS is inoperable.
	The owner or operator of an affected facility shall maintain a file of CEMS and performance test measurements, evaluations, and calibration checks for two years following the date of such activity.
40 CFR 60.8 (d), Testing	Notify the Administrator of any performance test at least 30 days prior to the test.
40 CFR 60.8 (e), Testing	Provide sampling ports, safe sampling platform, utilities and testing equipment prior to stack test.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.
40 CFR 61.5, Prohibited activities	Ninety days after the effective date of any standard pursuant to this part, no owner or operator shall operate any existing source subject to that standard in violation of the standard.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.
40 CFR 72.90, Annual compliance certification report	Sixty days after the end of the calendar year, the designated representative shall submit an annual compliance certification report for each affected unit.

Applicable Regulation	Applicable Requirement
40 CFR 75.3, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NO_x and CO_2 CEMS certification tests by Jan. 1, 1996.
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.
F.A.C. 62-4.030, General Prohibition	Any stationary installation which will be a source of air pollution shall not be operated, maintained, constructed, expanded, or modified without appropriate and valid permits issued by the DEP.
F.A.C. 62-4.090, Renewals	Submit an operating permit renewal application to the FDEP 180 days before the expiration of the operating permit.
F.A.C. 62-4.130, Plant Operation - Problems	If a facility is temporarily unable to comply with any of the conditions of a permit due to breakdown of equipment or destruction by hazard of fire, wind, or by other cause, the permittee shall immediately notify the DEP.
F.A.C. 62-4.160, Permit Conditions	The permittee shall allow authorized DEP personnel access to the facility where the permitted activity is located to have access to and copy any records that must be kept under conditions of the permit; inspect the facility, equipment, practices, or operations regulated or required under the permit; and sample or monitor any substances or parameters at any location reasonable necessary to assure compliance with permit conditions.
	Permits, or a copy thereof, shall be kept at the work site of the permitted activity.
	The permittee shall furnish all records and plans required under DEP rules; hold at the facility all monitoring information, reports, and records of data for at least three years from the date of the sample, measurement, report, or application.
F.A.C. 62-4.160, Permit Conditions (continued)	When requested by DEP, the permittee shall furnish, within a reasonable time, any information required by law which is needed to determine compliance with any permit.

Applicable Regulation	Applicable Requirement
F.A.C. 62-4.210, Construction Permits	No person shall construct any installation or facility which will reasonably be expected to be a source of air pollution without first applying for and receiving a construction permit from the DEP unless exempted by statute or DEP rule.
F.A.C. 62-210.300, Permits Required	An air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification
F.A.C. 62-210.350, Public Notice and Comment	A notice of proposed agency action on a permit application as described in F.A. C. 62-210.350(1)(a), where the proposed agency action is to issue the permit, shall be published by the applicant.
F.A.C. 62-210.360, Administrative Permit Corrections	A facility owner shall notify the DEP by letter of minor corrections to information contained in a permit. For operating permits, a copy shall be provided to the EPA.
F.A.C. 62-210.370, Reports	An Annual Operating Report for Air Pollution Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for all Title V sources. The annual operating report shall be submitted by March 1 of the following year.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting form malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.
F.A.C. 62-213.205, Annual Emissions Fee	Each Title V source must pay an annual emissions fee between January 15 and March 1 based on the factors identified in this rule.
F.A.C. 62-213.420, Permit Applications	Each Title V Acid Rain source that commenced operation on or before October 25, 1995 shall submit an operating permit application by June 15, 1996.
F.A.C. 62-214.320, Applications	New acid rain sources must submit an Acid Rain Part application in accordance with the provisions of 40 CFR Part 72.
F.A.C. 62-273.400, Air Pollution Episodes	Upon a declaration that an air pollution episode level exists (alert, warning, or emergency), any person responsible for the operation or conduct of activities which result in

Applicable Regulation	Applicable Requirement
	emission of air pollutants shall take actions as required in F.A.C. 62-273.400, 62-273.500, and 62-273.600.
F.A.C. 62-273.400, Air Alert	Upon a declaration of an air alert, open burning will be prohibited and motor vehicle operation minimized.
F.A.C. 62-273.500, Air Warning	Upon a declaration of an air warning, open burning will be prohibited and motor vehicle operation minimized. In addition, unnecessary space heating/cooling is prohibited.
F.A.C. 62-273.600, Air Emergency	Upon a declaration of an air emergency, operations will be restricted as prescribed under 62-273.600.
F.A.C. 62-296.320, General Pollutant Emission Limiting Standards	No person shall store, pump, handle, process, load, unload, or use in any process or installation, VOCs or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary by the DEP.
	No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
	Open burning in connection with industrial, commercial, or municipal operations is prohibited except if an emergency exists which requires immediate action to protect human health and safety.
	No person shall cause, let, permit, suffer, or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions.
	Each owner or operator of an emission unit subject to this rule shall install, calibrate, operate, and maintain a continuous monitoring system according to the requirements of 40 CFR 51, Appendix P and 40 CFR 60, Appendix B.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emission rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.

Attachment E

Precautions to Prevent Emissions of Unconfined Particulate Matter

Precautions to Prevent Emissions of Unconfined Particulate Matter

As a result of the construction of the simple cycle combustion turbines and the associated equipment at the project site minimal quantities of unconfined particulate matter (fugitive dust) may be released tot he atmosphere. These anticipated construction activities might be generally broken down into three phases as they relate to generating fugitive dust: debris removal, site preparation, and general construction. Because the equipment are being installed at new facility, JEA proposes to utilize watering to control fugitive dust. Watering is an effective stabilizing tool that controls fugitive dust by using water (or water combined with a surfactant) as a binder maintaining soil moisture content or establishing a crust which prevents soil movement under windy conditions. The water can be applied by any suitable means such as trucks, hoses, and/or sprinklers appropriate for site characteristics and size. For the construction phase of the project, it is proposed that water be applied as necessary during high wind conditions when fugitive dust is evident beyond the property boundary. The water will be applied using on or a combination of several methods listed above.

Attachment F

Supplemental Information for Construction Permit Application

Supplemental Information for Construction Permit Application

Please refer to the Prevention of Significant Deterioration Air Permit Application for Jacksonville Electric Authority's Brandy Branch Facility.

Attachment G

Unit Specific Applicable Requirements

170 MW Simple Cycle Combustion Turbine
Unit Specific Applicable Requirements

Applicable Regulations	Applicable Requirement
40 CFR 60.8, Performance tests	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup, the owner or operator shall conduct performance tests in accordance with applicable methods and procedures contained in 40 CFR 60.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.
40 CFR 60.332, Standard for nitrogen oxides	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the equation specified in 40 CFR 60.332(a)(1).
40 CFR 60.333, Standard for sulfur dioxide	No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.
40 CFR 60.334, Monitoring of operations	The owner or operator of any stationary gas turbine which uses water injection to control NO_x emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and ratio or water to fuel.
	The owner or operator of any stationary gas turbine shall monitor sulfur and nitrogen content as follows: • For fuel oil from bulk storage tank, the values shall be determined each time fuel is transferred to the storage tank. • For natural gas (no bulk storage), the values shall be determined andrecorded daily.
	The following periods of excess emissions shall be reported as defined in 40 CFR 60.334(c)(1): • Any one-hour period where the average water-to-fuel ratio falls below required limits or the nitrogen content of the fuel exceeds allowable limits. • Any daily period during which the sulfur content of the fuel fired exceeds 0.8 percent.

Applicable Regulations	Applicable Requirement
40 CFR 60.335, Test methods and procedures	The facility shall comply with the test methods and monitoring procedures defined in these provisions.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.
40 CFR 75.3, SUBPART A - General, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NO_x and CO_2 CEMS certification tests by Jan. 1, 1996.
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.
	No owner or operator of an affected unit shall use any alternative monitoring system or reference method without written approval from the DEP.
40 CFR 75.5, Prohibitions (continued)	No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method except for periods of recertification, or periods when calibrations, quality assurance, or maintenance is performed pursuant to 40 CFR 75.21 and Appendix B.
	No owner or operator shall retire or permanently discontinue use of the CEMS, any component thereof, except as allowed in 40 CFR 75.5(f).
40 CFR 75.10, SUBPART B - Monitoring Provisions, General operating requirements	The owner or operator shall install, certify, operate, and maintain a NO_x continuous emission monitoring system (NO_x pollutant monitor and an O_2 or CO_2 diluent gas monitor) with automated DAHS which records NO_x concentration, O_2 or CO_2 concentration, and NO_x emission rate.
	The owner or operator shall measure CO_2 emissions using a method specified in 40 CFR 75.10 through 75.16 and Appendices E and G.
	The owner or operator shall determine and record the heat input to the affected unit for every hour any fuel is combusted

Applicable Regulations	Applicable Requirement
	according to the procedures in Appendix F of this subpart.
	The owner or operator shall ensure that each CEMS, and component thereof, is capable of completing a minimum of one cycle of operation for each successive 15-minute interval.
40 CFR 75.11, Specific provisions for monitoring SO_2	Gas and oiled fired units shall measure and record SO_2 emissions as specified in 40 CFR 75, Appendix D.
40 CFR 75.20, SUBPART C - Operation and Maintenance Requirements, Certification and recertification procedures	The owner or operator shall ensure that each CEMS meets the initial certification requirements as specified in this section including notification and certification application.
	Whenever a replacement, modification, or change in the certified CEMS (including the DAHS and CO_2 systems) is made, the owner or operator shall recertify the CEMS, or component thereof, according to the procedures identified in 40 CFR 75.20(b) and (c).
	The owner or operator of a by-pass stack CEMS shall comply with all the requirements of 40 CFR 75.20 (a), (b), and (c) except only one nine-run relative accuracy test audit for certification or recertification of the flow monitor needs to be performed.
	The owner or operator using the optional SO_2 monitoring protocol of Appendix D of this subpart shall ensure that this system meets the certification requirements of 40 CFR 75.20(g).
40 CFR 75.21, Quality assurance and quality control requirements	The provisions of this part are suspended from July 17, 1995 through December 31, 1996. The owner or operator shall operate, calibrate, and maintain each CEMS according to the procedures of 40 CFR 75, Appendix B.
40 CFR 75.24, Out-of-control periods	If an out-of-control period occurs to a CEMS, the owner or operator shall take corrective action, as delineated in 40 CFR 75.24(c) through (e), and repeat tests applicable to the "out-of-control" parameter.
40 CFR 75.30, SUBPART D - Missing Data Substitution Procedures	The owner or operator shall provide substitute data according to the missing data procedures provided in 40 CFR 75.30 through 75.36.
40 CFR 75.51, SUBPART F	The owner or operator shall comply with the recordkeeping

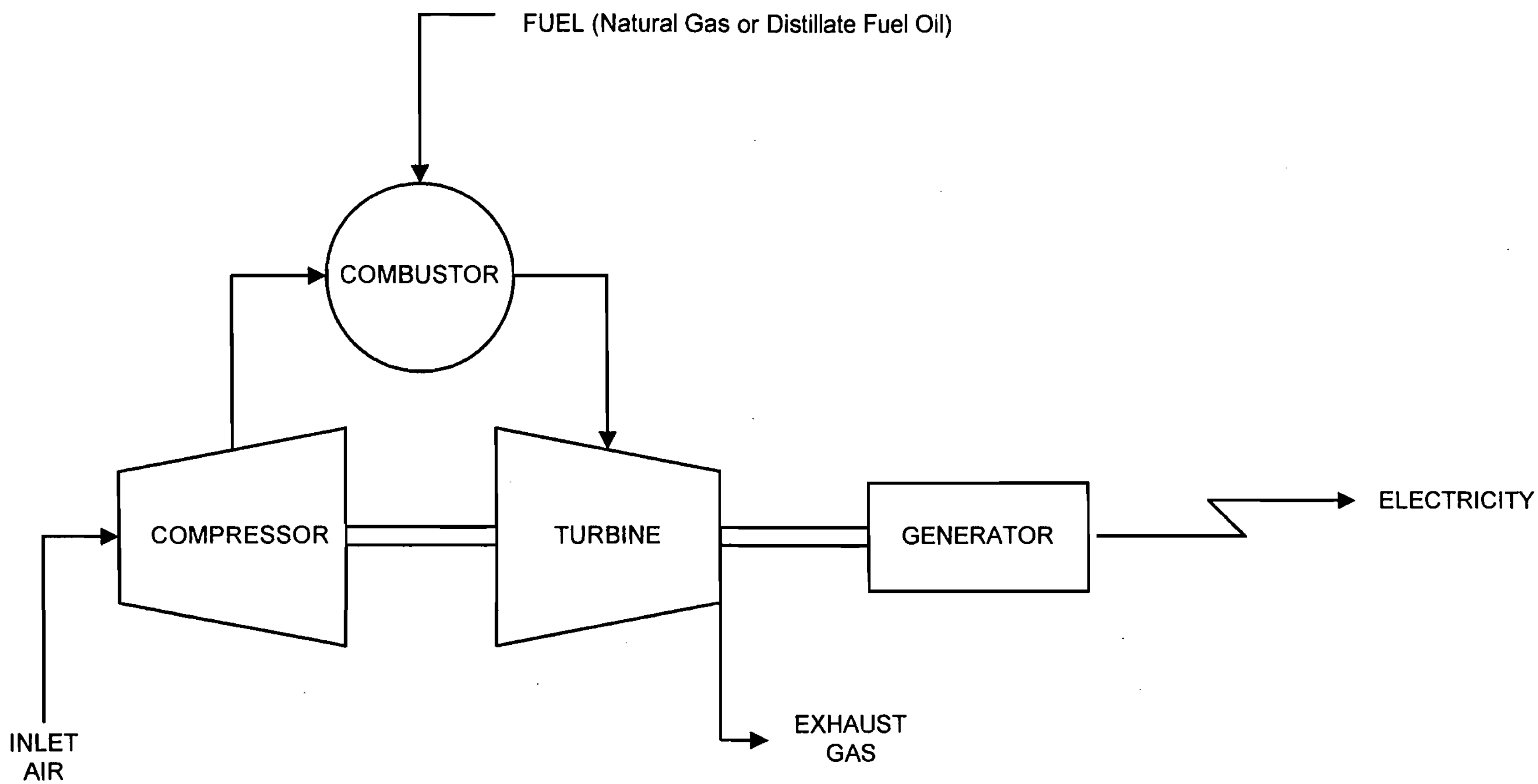
Applicable Regulations	Applicable Requirement
- Recordkeeping Requirements, General recordkeeping provisions for specific situations	requirements of 40 CFR 75.51(c)(1) through (3) when combusting natural gas and fuel oil.
40 CFR 75.52, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.52(a)(1) through (3) and 40 CFR 75.52(a)(5) through (7).
40 CFR 75.53, Monitoring Plan	The owner or operator shall prepare and maintain a monitoring plan pursuant to all applicable portions of this section.
40 CFR 75.54, General recordkeeping provisions	The owner or operator shall maintain a file of applicable measurements, data, reports, and other information required by 40 CFR 75 at the source for at least three (3) years according to the provisions of this section.
40 CFR 75.55, General recordkeeping provisions for specific situations	For SO_2 emission records, the owner or operator shall record information as required in 40 CFR 75.55(c) in lieu of the provisions of 40 CFR 75.54(c).
40 CFR 75.56, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.56(a)(1) through (3) and 40 CFR 75.56(a)(5) through (7).
40 CFR 75.60, SUBPART G - Reporting Requirements, General Provisions	The designated representative shall comply with all reporting requirements of this section for all submissions, and follow the procedures of 40 CFR 75.60(c) for any claims of confidential data.
40 CFR 75.61, Notifications	The designated representative shall submit proper notifications of specified data in this section.
40 CFR 75.62, Monitoring plan	The designated representative shall submit the monitoring plan no later than 45 days prior to the first scheduled certification test except as noted in this section.
40 CFR 75.64, Quarterly reports	The designated representative shall electronically submit the data specified in 40 CFR 75.64 (a), (b), and (c) on a quarterly basis.
40 CFR 75, Appendix A	The owner or operator shall adhere to all applicable specifications and test procedures identified in this section.
40 CFR 75, Appendix B	The owner or operator shall adhere to all applicable quality assurance and quality control procedures identified in this

Applicable Regulations	Applicable Requirement
	section.
40 CFR 75, Appendix C	The owner or operator shall adhere to all applicable missing data estimation procedures identified in this section.
40 CFR 75, Appendix D	The owner or operator shall adopt the protocol for SO_2 emissions monitoring, and adhere to all applicable requirements, as identified in this section.
40 CFR 75, Appendix F	The owner or operator shall adhere to all applicable conversion procedures identified in this section.
40 CFR 75, Appendix H, Revised Traceability Protocol No. 1	The owner or operator shall adhere to all applicable requirements identified in this section
40 CFR 75, Appendix J	The owner or operator shall adhere to all applicable requirements identified in this appendix.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.
F.A.C. 62-296.405	The owner must submit a written report of excess emissions for each unit requiring NSPS monitoring each calendar quarter to the FDEP.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emissions rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.

Attachment H

Process Flow Diagram

Jacksonville Electric Authority
Brandy Branch Facility
Facility ID: Unknown



Simple Cycle Combustion Turbine
Process Flow Diagram

Attachment I

Fuel Analysis or Specification

Fuel Analysis

Fuel is specified as pipeline quality sweet natural gas or No. 2 fuel oil containing no more than 0.05 percent sulfur.

Attachment J

Detailed Description of Control Equipment

Detailed Description of Control Equipment

1.) Low NO_x Burner: A technology that uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. this two-stage process ensures good mixing of the air and fuel, and minimizes the amount of air required which results in low NO_x emissions.

2.) Use of low sulfur fuel oil (0.05 percent) and the use of natural gas.

3.) Water Injection: A control technology used to limit NO_x emissions. The thermal NO_x contribution to total NO_x emission is reduced by lowering the combustion temperature through the use of water injection in the combustion zones of the combustion turbine. Water injection will be used only during oil firing.

Attachment K

Description of Stack Sampling Facilities

Stack Sampling Facilities

Vendors for these items have not yet been identified. A detailed description of the stack sampling facilities will be included with the operating permit application.

The stack sampling facilities will conform to F.A.C. Chapter 62-297.

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Chapter 62-297
Stationary Sources - Emissions Monitoring

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Chapter 62-297
Stationary Sources - Emissions Monitoring

62-297.100 Purpose and Scope.
The Department of Environmental Protection adopts this chapter to establish test procedures that shall be used to determine the compliance of air pollutant emissions units with emission limiting standards specified in or established pursuant to any of the stationary source rules of the Department. Words and phrases used in this chapter, unless clearly indicated otherwise, are defined at Rule 62-210.200, F.A.C.
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(a); Formerly 17-297.100; Amended 11-23-94, 3-13-96.

62-297.200 Definitions. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.100; Amended 6-29-93; Formerly 17-297.200; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.310 General Compliance Test Requirements.

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

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

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

(a) Combustion Turbines. (Reserved)

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

(3) Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.

(4) Applicable Test Procedures.

(a) Required Sampling Time.

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

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

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

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

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

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

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

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

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

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded Max. deviation between readings	Micrometer	+/-0.001" men of at least three readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

(5) Determination of Process Variables.

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

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

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

(a) Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

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

(c) Sampling Ports.

1. All sampling ports shall have a minimum inside diameter of 3 inches.

2. The ports shall be capable of being sealed when not in use.

3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d). Work Platforms.

1. inimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e). Access to Work Platform.

1 Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f). Electrical Power.

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

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

(g). Sampling Equipment Support.

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

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

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

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

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

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

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

(a) General Compliance Testing.

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions

unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

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

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

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

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

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

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

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from permitting at Rule 62-210.300(3)(a), F.A.C., or units permitted under the General Permit provisions at Rule 62- 210.300(4)(a)1. through 7., F.A.C.

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

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

(8) Test Reports.

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

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

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

1. The type, location, and designation of the emissions unit tested.

2. The facility at which the emissions unit is located.

3. The owner or operator of the emissions unit.

4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.

5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.

7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

8. The date, starting time and duration of each sampling run.

9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.

10. The number of points sampled and configuration and location of the sampling plane.

11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

l2. The type, manufacturer and configuration of the sampling equipment used.

13. Data related to the required calibration of the test equipment.

14. Data on the identification, processing and weights of all filters used.

15. Data on the types and amounts of any chemical solutions used.

16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.

17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18. All measured and calculated data required to be determined by each applicable test procedure for each run.

19. The detailed calculations for one run that relate the collected data to the calculated emission rate.

20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(b); Formerly 17-297.310; Amended 11-23-94, 3-13-96, 10-28-97.

62-297.330 Applicable Test Procedures. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, 470.025, F.S.
History: Formerly 17-2.710, Amended 11-62-92, 12-02-92, Formerly 17-297.330; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.340 Frequency of Compliance Tests. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(2); Formerly 17-297.340; Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.345 Stack Sampling Facilities Provided by the Owner of an Emissions Unit. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(4), Formerly 17-297.345, Amended 11-23-94, 1-1-96, Repealed 3-13-96.

62-297.350 Determination of Process Variables. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(5), Formerly 17-297.350, Amended 11-23-94. Repealed 3-13-96.

62-297.400 EPA Methods Adopted by Reference. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(1)(c), Formerly 17-297.400, Amended 11-23-94, Repealed 1-1-96.

62-297.401 Compliance Test Methods.

This rule adopts the test methods to be used where a compliance test is required by Department air pollution rule or air permit. The EPA test methods and quality assurance procedures listed in this rule and contained in 40 CFR Part 51, Appendix M, 40 CFR Part 60, Appendix A and F, 40 CFR Part 61, Appendix B and C and 40 CFR Part 63, Appendix A, are adopted and incorporated by reference in Rule 62-204.800, F.A.C. The EPA test methods that are adopted by reference in Rule 62-204.800, F.A.C., are adopted in their entirety except for those provisions referring to approval of alternative procedures by the Administrator. For purposes of this rule, such alternative procedures may only be approved by the Secretary or his or her designee in accordance with Rule 62-297.620, F.A.C.

(1)(a) EPA Method 1 -- Sample and Velocity Traverses for Stationary sources -- 40 CFR 60 Appendix A.

(b) EPA Method 1A -- Sample and Velocity Traverses for Stationary Sources with Small Stacks or Ducts -- 40 CFR 60 Appendix A.

(2) EPA Method 2 -- Determination of Stack Gas Velocity and Volumetric Flow Rate -- 40 CFR 60 Appendix A.

(a) EPA Method 2A -- Direct Measurement of Gas Volume Through Pipes and Small Ducts -- 40 CFR 60 Appendix A.

(b) EPA Method 2B -- Determination of Exhaust Gas Volume Flow Rate from Gasoline Vapor Incinerators -- 40 CFR 60 Appendix A.

(c) EPA Method 2C -- Determination of Stack Gas Velocity and Volumetric Flow Rate in Small Stacks and Ducts (Standard Pitot Tube) -- 40 CFR 60 Appendix A

(d) EPA Method 2D -- Measurement of Gas Volumetric Flow Rates in Small Pipes and Ducts -- 40 CFR 60 Appendix A.

(3) EPA Method 3 -- Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight -- 40 CFR 60 Appendix A.

(a) EPA Method 3A -- Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A

(b) (Reserved).

(4) EPA Method 4 -- Determination of Moisture Content in Stack Gases -- 40 CFR 60 Appendix A.

(5) EPA Method 5 -- Determination of Particulate Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 5A -- Determination of Particulate Emissions from the Asphalt Processing and Asphalt Roofing Industry -- 40 CFR 60 Appendix A.

(b) EPA Method 5B -- Determination of Nonsulfuric Acid Particulate Matter from Stationary Sources -- 40 CFR 60 Appendix A.

(c) Reserved.

(d) EPA Method 5D -- Determination of Particulate Matter Emissions from Positive Pressure Fabric Filters -- 40 CFR 60 Appendix A.

(e) EPA Method 5E -- Determination of Particulate Emissions from the Wool Fiberglass Insulation Manufacturing Industry -- 40 CFR 60 Appendix A.

(f) EPA Method 5F -- Determination of Nonsulfate Particulate Matter from Stationary Sources -- 40 CFR 60 Appendix A.

(g) EPA Method 5G -- Determination of Particulate Emissions from Wood Heaters from a Dilution Tunnel Sampling Location -- 40 CFR 60 Appendix A.

(h) EPA Method 5H -- Determination of Particulate Emissions from Wood Heaters from a Stack Location -- 40 CFR 60 Appendix A.

(6) EPA Method 6 -- Determination of Sulfur Dioxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 6A -- Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions From Fossil Fuel Combustion Sources -- 40 CFR 60 Appendix A.

(b) EPA Method 6B -- Determination of Sulfur Dioxide and Carbon Dioxide Daily Average Emissions From Fossil Fuel Combustion Sources -- 40 CFR 60 Appendix A.

(c) EPA Method 6C -- Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A.

(7) EPA Method 7 -- Determination of Nitrogen Oxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 7A -- Determination of Nitrogen Oxide Emissions from Stationary Sources -- Ion Chromatographic Method -- 40 CFR 60 Appendix A.

(b) EPA Method 7B -- Determination of Nitrogen Oxide Emissions from Stationary Sources (Ultraviolet Spectrophotometry) -- 40 CFR 60 Appendix A.

(c) EPA Method 7C -- Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline--Permanganate/
- Colorimetric Method -- 40 CFR 60 Appendix A.

(d) EPA Method 7D -- Determination of Nitrogen Oxide Emissions from Stationary Sources - Alkaline--Permanganate/
- Ion Chromatographic Method -- 40 CFR 60 Appendix A.

(e) EPA Method 7E -- Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure) -- 40 CFR 60 Appendix A.

(8) EPA Method 8 -- Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(9)(a) EPA Method 9 -- Visual Determination of the Opacity of Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(b) Alternate Method 1 -- Determination of the Opacity of Emissions from Stationary Sources Remotely by Lidar -- 40 CFR 60 Appendix A.

(c) DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six- minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

(10) EPA Method 10 -- Determination of Carbon Monoxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 10A -- Determination of Carbon Monoxide Emissions in Certifying Continuous Emission Monitoring Systems at Petroleum Refineries -- 40 CFR 60 Appendix .

(b) EPA Method 10B -- Determination of Carbon Monoxide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(11) EPA Method 11 -- Determination of Hydrogen Sulfide Content of Fuel Gas Streams in Petroleum Refineries -- 40 CFR 60 Appendix A.

(12) EPA Method 12 -- Determination of Inorganic Lead Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(13) EPA Methods 13A and 13B.

(a) EPA Method 13A -- Determination of Total Fluoride Emissions from Stationary Sources -- SPADNS --- Zirconium Lake Method -- 40 CFR 60 Appendix A.

(b) EPA Method 13B -- Determination of Total Fluoride Emissions from Stationary Sources -- Specific Ion Electrode Method -- 40 CFR 60 Appendix A.

(14) EPA Method 14 -- Determination of Fluoride Emissions from Potroom Roof Monitors of Primary Aluminum Plants -- 40 CFR 60 Appendix A.

(15) EPA Method 15 -- Determination of Hydrogen Sulfide, Carbonyl Sulfide and Carbon Disulfide Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 15A -- Determination of Total Reduced Sulfur Emissions from Sulfur Recovery Plants in Petroleum Refineries -- 40 CFR 60 Appendix A.

(16) EPA Method 16 -- Semicontinuous Determination of Sulfur Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(a) EPA Method 16A -- Determination of Total Reduced Sulfur Emissions from Stationary Sources (Impinger Technique) -- 40 CFR 60 Appendix A.

(b) EPA Method 16B -- Determination of Total Reduced Sulfur Emissions from Stationary Sources -- 40 CFR 60 Appendix A.

(17) EPA Method 17 -- Determination of Particulate Emissions from Stationary Sources (In-Stack Filtration Method) -- 40 CFR 60 Appendix A.

(18) EPA Method 18 -- Measurement of Gaseous Organic Compound Emissions by Gas Chromatography -- 40 CFR 60 Appendix A.

(19) EPA Method 19 -- Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide and Nitrogen Oxides Emission Rates -- 40 CFR 60 Appendix A.

(20) EPA Method 20 -- Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines -- 40 CFR 60 Appendix A.

(21) EPA Method 21 -- Determination of Volatile Organic Compound Leaks -- 40 CFR 60 Appendix A.

(22) EPA Method 22 -- Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares -- 40 CFR 60 Appendix A.

(23) EPA Method 23 -- Determination of Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofurans from Stationary Sources -- 40 CFR 60 Appendix A.

(24) EPA Method 24 -- Determination of Volatile Matter Content, Water Content, Density, Volume Solids, and Weight Solids of Surface Coatings -- 40 CFR 60 Appendix A.

(a) EPA Method 24A -- Determination of Volatile Matter Content and Density of Printing Inks and Related Coatings -- 40 CFR 60 Appendix A.

(b) No change.

(25) EPA Method 25 -- Determination of Total Gaseous Nonmethane Organic Emissions as Carbon -- 40 CFR 60 Appendix A.

(a) EPA Method 25A -- Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer -- 40 CFR 60 Appendix A.

(b) EPA Method 25B -- Determination of Total Gaseous Organic Concentration Using a Nondispersive Infrared Analyzer -- 40 CFR 60 Appendix A.

(26) EPA Method 26 -- Determination of Hydrogen Chloride Emissions From Stationary Sources -- 40 CFR 60, Appendix A.

(a) EPA Method 26A -- Determination of Hydrogen Halide and Halogen Emissions From Stationary Sources - Isokinetic Method -- 40 CFR 60, Appendix A

(27) EPA Method 27 -- Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure-Vacuum Test -- 40 CFR 60 Appendix A.

(28) EPA Method 28 -- Certification and Auditing of Wood Heaters -- 40 CFR 60 Appendix A.

(a) EPA Method 28A -- Measurement of Air to Fuel Ratio and Minimum Achievable Burn Rates for Wood-Fired Appliances -- 40 CFR 60 Appendix A.

(29) EPA Method 29 -- Determination of Metals Emission from Stationary Sources -- 40 CFR 60 Appendix A.

(30) Reserved.

(31) 40 CFR 60 Appendix F -- Quality Assurance Procedures -- .

(32) EPA Method 101 -- Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants - Air Streams -- 40 CFR 61 Appendix B.

(a) EPA Method 101A -- Determination of Particulate and Gaseous Mercury Emissions from Sewage Sludge Incinerators -- 40 CFR 61 Appendix B.

(33) EPA Method 102 -- Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants - Hydrogen Streams -- 40 CFR 61 Appendix B.

(34) EPA Method 103 -- Beryllium Screening Method -- 40 CFR 61 Appendix B.

(35) EPA Method 104 -- Determination of Beryllium Emissions from Stationary Sources -- 40 CFR 61 Appendix B.

(36) EPA Method 105 -- Determination of Mercury in Wastewater Treatment Plant Sewage Sludges -- 40 CFR 61 Appendix B.

(37) EPA Method 106 -- Determination of Vinyl Chloride Emissions from Stationary Sources -- 40 CFR 61 Appendix B.

(38) EPA Method 107 -- Determination of Vinyl Chloride Content of Inprocess Wastewater Samples, and Vinyl Chloride Content of Polyvinyl Chloride Resin, Slurry, Wet Cake, and Latex Samples -- 40 CFR 61 Appendix B.

(a) EPA Method 107A -- Determination of Vinyl Chloride Content of Solvents, Resin-Solvent Solution, Polyvinyl Chloride Resin, Resin Slurry, Wet Resin, and Latex Samples -- 40 CFR 61 Appendix B.

(39) EPA Method 108 -- Determination of Particulate and Gaseous Arsenic Emissions -- 40 CFR 61 Appendix B.

(a) EPA Method 108A -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(b) EPA Method 108B -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(c) EPA Method 108C -- Determination of Arsenic Content in Ore Samples from Nonferrous Smelters -- 40 CFR 61 Appendix B.

(40) 40 CFR 61 Appendix C -- Quality Assurance Procedures.

(41) EPA Method 201 -- Determination of PM_{10} Emissions (Exhaust Gas Recycle Procedure) -- 40 CFR 51 Appendix M.

(a) EPA Method 201A -- Determination of PM_{10} Emissions (Constant Sampling Rate Procedure) -- 40 CFR 51 Appendix M.

(42) EPA Method 202 -- Determination of Condensible Particulate Emissions from Stationary Sources -- 40 CFR 51 Appendix M.

(43) EPA Method 301 -- Field Data Validation Protocol -- 40 CFR Part 63, Appendix A.

(44) EPA Method 303 -- Coke Oven Door Emissions -- 40 CFR Part 63, Appendix A.
Specific Authority 403.061 FS.
Law Implemented 403.021, 403.031, 403.061, 403.087 FS.
History Formerly 17-2.700(6)(b), Amended 10-14-92, 6-29-93; Formerly 17-297.401; Amended 11-23-94, 1-1-96, 3-13-96, 10-7-96.

62-297.411 DEP Method 1. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)1, Formerly 17-297.411, Amended 11-23-94, Repealed 1-1-96.

62-297.412 DEP Method 2 (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)2, Formerly 17-297.412, Repealed 1-1-96.

62-297.413 DEP Method 3. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)3, Formerly 17-297.413, Repealed 1-1-96.

62-297.414 DEP Method 4. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)4, Formerly 17-297.414, Repealed 1-1-96.

62-297.415 DEP Method 5. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)5.a, Formerly 17-297.415; Amended 11-23-94, Repealed 1-1-96.

62-297.416 DEP Method 5A. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)5.b, Formerly 17-297.416, Repealed 1-1-96.

62-297.417 DEP Method 6. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)6, Formerly 17-297.417, Amended 11-23-94, Repealed 1-1-96.

62-297.418 DEP Method 7. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)7, Formerly 17-297.418, Repealed 1-1-96.

62-297.419 DEP Method 8. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)8, Formerly 17-297.419, Repealed 1-1-96.

62-297.420 DEP Method 9. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)9, Formerly 17-297.420, Amended 11-23-94, Repealed 3-13-96.

62-297.421 DEP Method 10. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)10, Formerly 17-297.421, Repealed 1-1-96.

62-297.422 DEP Method 11. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 62-2.700(6)(a)11, Formerly 17-297.422, Repealed 1-1-96.

62-297.423 EPA Method 12. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)12, Formerly 17-297.423, Amended 11-23-94, 1-1-96.

62-297.424 DEP Method 13. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(a)13, Formerly 17-297.424, Repealed 1-1-96.

62-297.440 Supplementary Test Procedures.
The following test procedures are adopted by reference. Copies of these documents are available from the emissions units set forth below. Copies may also be inspected at the Department's Tallahassee Office.

(1) ASTM Methods. Standard Methods published by the American Society for Testing and Materials are available from the Society at 1916 Race Street, Philadelphia, Pennsylvania 19103.

(a) ASTM D 322-67, 1972. Standard Method of Test for Dilution of Gasoline Engine Crankcase Oils.

(b) ASTM D 396-76. Standard Specification for Fuel Oils, superceding ASTM D 396-69.

(c) ASTM D 2880-76. Standard Specification for Gas Turbine Fuel Oils, superceding ASTM D 2880-71.

(d) ASTM D 975-77. Standard Specification for Diesel Fuel Oils, superceding ASTM D 975-68.

(e) ASTM D 323-72. Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method).

(f) ASTM D 97-66. Standard Test Method for Pour Point of Petroleum Oils.

(g) ASTM D 4057-88. Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(h) ASTM D 129-91. Standard Test Method for Sulfur in Petroleum Products (General Bomb Method).

(i) ASTM D 2622-94. Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry.

(j) ASTM D 4294-90. Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy.

(2) EPA Reports -- EPA occasionally publishes test methods and emission control guidelines in a report format. These documents are available (unless otherwise stated) from the National Technical Information Services, 5286 Port Royal Road, Springfield, Virginia 22216, and may be inspected at the Department's Tallahassee Office.

(a) Petroleum Liquid Storage.

1. Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks, EPA 450/2-78-047, p. 5-3.

2. Control of Volatile Organic Emissions from Storage of Petroleum Liquids in Fixed- Roof Tanks, EPA 450/2-77-036, p. 6-2.

(b) Gasoline Bulk Terminals.

1. Vapor Control System Test.

a. VOC emissions from the vapor control system shall be determined by the method given in Appendix A of EPA 450/2-77-026, except that an adequate sampling time shall be at least six (6) hours of operation. For continuous vapor processing systems at least 80,000 gallons (302,800 liters) of gasoline shall be loaded during the test. For intermittent vapor processing systems, at least 80,000 gallons (302,800 liters) of gasoline shall be loaded during the test and at least two full cycles of operation of the vapor processing system shall occur. This test shall be performed prior to the date of compliance and annually thereafter. Test results records shall be maintained at the terminal until the subsequent annual test shall be made available to the Department upon request.

b. Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals, EPA 450/2-77-026, Appendix A. Emission Test Procedure for Tank Truck Gasoline Loading Terminals.

2. Vapor Leak Detection.

a. During loading or unloading operations at bulk terminals, there shall be no reading greater than or equal to 100 percent of the lower explosive level (LEL), measured as propane at 1 in. (2.5 centimeters) around the perimeter of a potential leak source as detected by a combustible gas detector using the procedure described in Appendix B of EPA 450/2-78-051.

b. Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems, EPA 450/2-78-051, Appendix B, Gasoline Vapor Leak Detection Procedures by Combustible Gas Detector.

(c) Gasoline Service Stations.

1. Design Criteria for Stage I Vapor Control: Gasoline Service Stations, USEPA, OAQPS, ESED, November, 1975.

2. [Reserved]

(d) Non-destructive Control Devices.

1. Measurement of Volatile Organic Compounds, EPA 450/2-78-041, Attachment 3, Alternate Test for Direct Measurement of Total Gaseous Organic Compounds Using a Flame Ionization Analyzer.

2. [Reserved]

(e) Perchloroethylene Dry Cleaning Systems.

1. Control of Volatile Organic Emissions from Perchloroethylene Dry Cleaning Systems, EPA 450/2-78-050, p. 6-3, Compliance Procedures, Liquid Leakage.

2. RACT Compliance Guidance for Carbon Absorbers on Perchloroethylene Dry Cleaners. Task No. 119, Contract No. 68-01-4147. EPA, DSSE, May, 1980, pp. 8-21, Appendices A and B.

(f) Cross Recovery Determination. When determining if a kraft recovery furnace is a straight kraft or cross recovery furnace the procedure in 40 CFR 60.285(d)(3) of Subpart BB shall be used.

(3) American Conference of Governmental Industrial Hygienists, Recommended Practices -- Industrial Ventilation: A Manual of Recommended Practice. Equipment Specifications published in the 16th Edition of the Industrial Ventilation Manual (or any subsequent versions approved by the Department) are available from the American Conference of Governmental Industrial Hygienists, Committee on Industrial Ventilation, P. O. Box 16153, Lansing, Michigan 48901, and may be inspected at the Department's Tallahassee Office.

(4) American Petroleum Institute (API) Recommended Practices -- These are available from the API, 2101 L Street, Northwest, Washington, D. C. 20037

(a) API Standard 650, Welded Steel Tanks for Oil Storage, Sixth Edition, Revision 1, May 15, 1978.

(b) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February, 1980.

(c) API 1004, Bottom Loading and Vapor Recovery for MC-306 Tank Motor Vehicles, Fourth Edition, September 1, 1977.

(5) Technical Association of the Pulp and Paper Industry (TAPPI), Test Methods -- These are available from TAPPI, P. O. Box 105113, Atlanta, Georgia 30348.

(a) TAPPI Method T.624, Analysis of Soda and Sulfate White and Green Liquors.

(b) (Reserved).

(6) Sulphur Development Institute of Canada (SUDIC) Sampling and Testing Sulphur Forms -- These are available from SUDIC, Box 950, Bow Valley Square 1, 830, 202-6 Avenue S. W., Calgary, Alberta T2P 2W6.

(a) S1-77. Collection of a Gross Sample of Sulphur.

(b) S2-77. Sieve Analysis of Sulphur Forms, except paragraph 4.3 concerning wet sieving is not adopted.

(c) S3-77. Determination of Material Finer than No. 50 (300um) Sieve in Sulphur Forms by Washing.

(d) S5-77. Determination of Friability of Sulfur Forms.

(7) EPA VOC Capture Efficiency Test Procedures. Adopted by reference is an EPA memo dated April 16, 1990 entitled, "Guidelines for Developing a State Protocol for the Measurement of Capture Efficiency." A copy can be obtained by writing to: Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

(a) Procedure F.1 -- Fugitive VOC Emissions from Temporary Enclosures.

(b) Procedure F.2 -- Fugitive VOC Emissions from Building Enclosures.

(c) Procedure G.1 -- Captured VOC Emissions.

(d) Procedure G.2 -- Captured VOC Emissions (dilution technique).

(e) Procedure L -- VOC in Liquid Input Stream.

(f) Procedure T -- Criteria for and Verification of Permanent or Temporary Total Enclosure.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(6)(c); Amended 6-29-93, Formerly 17-297.440, Amended 11-23-94, 1-1-96.

62-297.450 EPA VOC Capture Efficiency Test Procedures.

(1) Applicability. The requirements set forth in Rules 62-297.450(2) and (3), F.A.C., shall apply to all regulated VOC emitting emissions units employing a control system pursuant to Rules 62-296.501 through 62-296.516, F.A.C., and Rule 62-296.800, F.A.C., except as provided in Rules 62-297.450(1)(a) and (b), F.A.C.

(a) If an owner or operator installs a Permanent Total Enclosure that meets the specifications of Procedure T, and which directs all VOC to a control device, the capture efficiency is assumed to be 100 percent, and the facility owner or operator is exempted from the requirements described in Rule 62-297.450(2) ; F.A.C. This does not exempt the owner or operator from conducting any required control device efficiency test.

(b) If the owner or operator of an affected activity, process, or emissions unit uses a nondestructive control device designed to collect and recover VOC (e.g. carbon adsorber), an explicit measurement of capture efficiency is not necessary if the owner or operator is able to equate solvent usage with solvent recovery on a 24-hour (daily) basis, rather than a 30-day weighted average, and can determine this within 72 hours following each 24-hour period, and one of the following two criteria is also met:

1. The solvent recovery system (i.e., capture and control system) is dedicated to a single activity, process line, or emissions unit (e.g., one process line venting to a carbon adsorber system), or

2. The solvent recovery system controls multiple activities, process lines, or emissions units and the owner or operator is able to demonstrate that the overall control (i.e., the total recovered solvent VOC divided by the sum of liquid VOC input to all activities, process lines, or emissions units venting of the control system) meets or exceeds the most stringent emission standard applicable for any activity, process line, or emissions unit venting to the control system.

(c) If the conditions given above in Rule 62-297.450(1)(b), F.A.C., are met, the overall emission reduction efficiency of the system can be determined by dividing the recovered liquid VOC by the input liquid VOC. The general procedure for this determination is given in 40 CFR 60.433, which is adopted by reference.

(2) Specific Requirements. The capture efficiency of a capture system shall be determined using one of the following EPA procedures, or an alternate capture efficiency test procedure if approved by the Department under the provisions of Rule 62-297.620, F.A.C.

(a) Gas/gas method using a Temporary Total Enclosure. The EPA specifications to determine whether an enclosure is considered a Temporary Total Enclosure are given in Procedure T, which is adopted by reference in Rule 62-297.440, F.A.C. The capture efficiency equation to be used for this procedure is:

$$CE = Gw/(Gw + Fw)$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)

Gw = mass of VOC captured and delivered to control device using a Temporary Total Enclosure

Fw = mass of fugitive VOC that escapes from a Temporary Total Enclosure Procedure G.1 or Procedure G.2 is used to obtain Gw. Procedure F.1 is used to obtain Fw.

(b) Liquid/gas method using Temporary Total Enclosure. The EPA specifications to determine whether an enclosure is considered a Temporary Total Enclosure are given in Procedure T, which is adopted by reference in Rule 62-297.440, F.A.C. The capture efficiency equation to be used for this procedure is:

$$CE = (L-F)/L$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
L = mass of liquid VOC input to the activity, process, or emissions unit
F = mass of fugitive VOC that escapes from a Temporary Total Enclosure
Procedure L is used to obtain L. Procedure F.1 is used to obtain F.

(c) Gas/gas method using the building or room in which the affected activity, process, or emissions unit is located as the enclosure and in which G and F are measured while operating only the affected activity, process, or emissions unit. All fans and blowers in the building or room must be operated as they would under normal production. The capture efficiency equation to be used for this procedure is:

$$CE = G/(G + F \text{ sub } B)$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
G = mass of VOC captured and delivered to a control device
F_B = mass of fugitive VOC that escapes from building enclosure

Procedure G.1 or Procedure G.2 is used to obtain G. Procedure F.2 is used to obtain F_B.

(d) Liquid/gas method using the building or room in which the affected activity, process, or emissions unit located as the enclosure and in which L and F are measured while operating only the affected activity, process, or emissions unit. All fans and blowers in the building or room shall be operated as they would under normal production. The capture efficiency equation to be used for this procedure is:

$$CE = (L-F_B)/L$$

where:

CE = capture efficiency, decimal fraction, times 100 (percentage)
L = mass of liquid VOC input to the activity, process, or emissions unit
F_B = mass of fugitive VOC that escapes from building enclosure

Procedure L is used to obtain L. Procedure F.2 is used to obtain F sub B.

(3) Sampling Requirements. A capture efficiency test shall consist of at least three sampling runs. Each run shall cover at least one complete production cycle, but shall be at least 3 hours long. The sampling time for each run need not exceed 8 hours, even if the production cycle has not been completed.

(4) Recordkeeping and Reporting.

(a) The owner or operator of an affected activity, process, or emissions unit shall submit to the Department a list of the procedures that will be used for the capture efficiency tests at the owner or operator's facility. A copy of the list shall be kept on file at the affected facility.

(b) Required test reports shall be submitted to the Department within forty-five (45) days of the test date. A copy of the results shall be kept on file at the facility.

(c) If any physical or operational change is made to a control system, the owner or operator of the affected facility shall notify the Department of the change within ten (10) working days after making such change. The Department shall require the owner or operator of the affected activity, process, or emissions unit to conduct a new capture efficiency test if the Department has reason to believe (based on engineering calculations or empirical evidence) that a physical or operational change made to the capture system has decreased the overall emissions reduction efficiency of the system.

(d) Notwithstanding the provisions of Rule 62-297.340(1), F.A.C., the owner or operator of an affected activity, process, or emissions unit shall notify the Department thirty (30) days prior to performing any capture efficiency and/or control efficiency tests.

(e) The owner or operator of an affected activity, process, or emissions unit using a Permanent Total Enclosure shall demonstrate that this enclosure meets the requirement given in Procedure T for a Permanent Total Enclosure during any required control device efficiency test.

(f) The owner or operator of an affected activity, process, or emissions unit using a Temporary Total Enclosure shall demonstrate that this enclosure meets the requirements given in Procedure T for a Temporary Total Enclosure during any required control device efficiency test.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(7); Amended 6-29-93, Formerly 17-297.450, Amended 11-23-94, 1-1-96.

62-297.500 Continuous Emission Monitoring Requirements. (Repealed)
Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, 470.025, F.S.
History: Formerly 17-2.710, Amended 11-62-92, 12-02-92; 6-29-93; Formerly 17-297.500; Repealed 11-23-94.

62-297.520 EPA Continuous Monitor Performance Specifications. This rule adopts the continuous monitor performance specifications to be used where required by Department air pollution rule or air permit. The EPA performance specifications listed in this rule and contained in 40 CFR 60, Appendix B, are adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(1) Performance Specification 1--Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.

(2) Performance Specification 2--Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources.

(3) Performance Specification 3--Specifications and Test Procedures for O_2 and CO_2 Continuous Emission Monitoring Systems in Stationary Sources.

(4) Performance Specification 4--Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

(5) Performance Specification 4A--Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources.

(6) Performance Specification 5--Specifications and Test Procedures for TRS Continuous Emission Monitoring Systems in Stationary Sources.

(7) Performance Specification 6--Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources.

(8) Performance Specification 7--Specifications and Test Procedures for Hydrogen Sulfide Continuous Emission Monitoring Systems in Stationary Sources.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: New 6-29-93, Formerly 17-297.520, Amended 11-23-94, 3-13-96.

62-297.570 Test Reports. (Repealed)

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(8), Formerly 17-297.570, Amended 11-23-94, Repealed 3-13-96.

62-297.620 Exceptions and Approval of Alternate Procedures and Requirements.

(1) The owner or operator of any emissions unit subject to the provisions of this chapter may request in writing a determination by the Secretary or his/her designee that any requirement of this chapter (except for any continuous monitoring requirements) relating to emissions test procedures, methodology, equipment, or test facilities shall not apply to such emissions unit and shall request approval of an alternate procedures or requirements.

(2) The request shall set forth the following information, at a minimum:

(a) Specific emissions unit and permit number, if any, for which exception is requested.

(b) The specific provision(s) of this chapter from which an exception is sought.

(c) The basis for the exception, including but not limited to any hardship which would result from compliance with the provisions of this chapter.

(d) The alternate procedure(s) or requirement(s) for which approval is sought and a demonstration that such alternate procedure(s) or requirement(s) shall be adequate to demonstrate compliance with applicable emission limiting standards contained in the rules of the Department or any permit issued pursuant to those rules.

(3) The Secretary or his/her designee shall specify by order each alternate procedure or requirement approved for an individual emissions unit source in accordance with this section or shall issue an order denying the request for such approval. The Department's order shall be final agency action, reviewable in accordance with Section 120.57, Florida Statutes.

(4) In the case of an emissions unit which has the potential to emit less than 100 tons per year of particulate matter and is equipped with a baghouse, the Secretary or the appropriate Director of District Management may waive any particulate matter compliance test requirements for such emissions unit specified in any otherwise applicable rule, and specify an alternative standard of 5% opacity. The waiver of compliance test requirements for a particulate emissions unit equipped with a baghouse, and the substitution of the visible emissions standard, shall be specified in the permit issued to the emissions unit.

If the Department has reason to believe that the particulate weight emission standard applicable to such an emissions unit is not being met, it shall require that compliance be demonstrated by the test method specified in the applicable rule.

Specific Authority: 403.061, F.S.

Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(3); Amended 6-29-93; Formerly 17-297.620; Amended 11-23-94.

Attachment L

Compliance Test Report

Compliance Test Report

A compliance test report will be included with the operating permit application after construction and initial testing has been completed.

Attachment M

Procedures for Startup and Shutdown

Procedures for Startup and Shutdown

After a normal start up is initiated, the time is documented when the turbine starts firing. The turbine then continues with a normal start up and warm up. Time is documented again when the breaker closes. Upon the generator reaching 60 MW, the water injection pump is turned on (fuel oil only), and flow is established to the turbine. When the NO_x emissions are controlled and stable, the time is again documented. The turbine is then released to dispatch the necessary load.

When a shut down occurs, the load on the generator is reduced to 60 MW and the water injection pumps are taken out of service (fuel oil only-this time is documented). Time is again recorded when the turbine stops firing.

Attachment N

Operation and Maintenance Plan

Operation and Maintenance Plan

An operation and maintenance plan will be submitted if required by the construction permit.

Attachment O

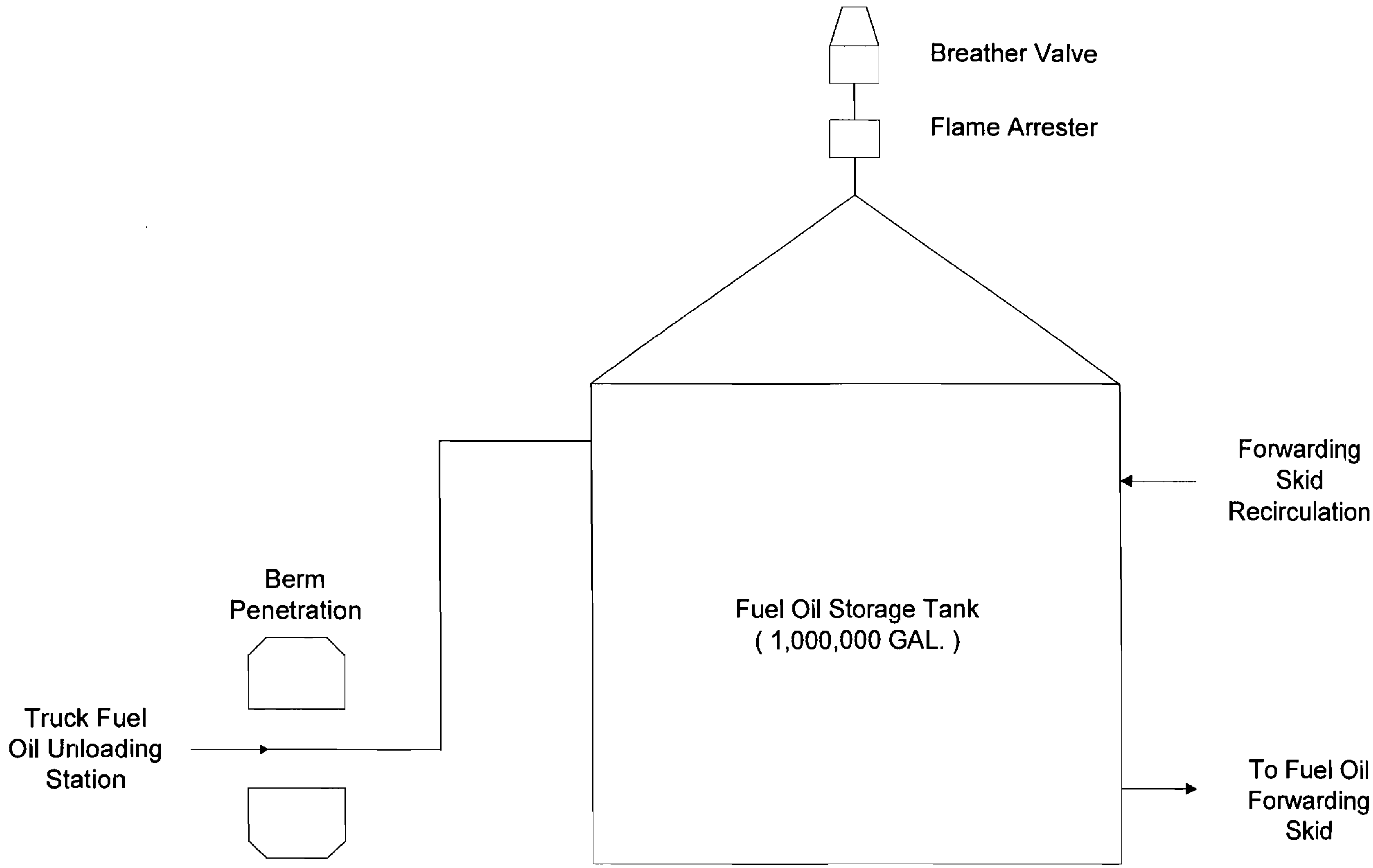
Unit Specific Applicable Requirements

1,000,000 Gallon Fuel Oil Storage Tank
Unit Specific Applicable Requirements

Applicable Regulations	Applicable Requirement
40 CFR 60, Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 19984.
40 CFR 60.116b, Monitoring of Operations	The owner or operator shall keep records according to the provisions of 40 CFR 60.116b (a) and (b) for a period of at least two (2) years.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.
F.A.C. 62-210.700, Excess Emissions	In case of Excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130.

Attachment P

Process Flow Diagram


Breather Valve
Flame Arrester
Forwarding
Skid
Recirculation
Berm
Penetration
Fuel Oil Storage Tank
(1,000,000 GAL.)
Truck Fuel
Oil Unloading
Station
To Fuel Oil
Forwarding
Skid

TANKS PROGRAM 3.1
EMISSIONS REPORT - DETAIL FORMAT
TANK IDENTIFICATION AND PHYSICAL CHARACTERISTICS

Identification	
Identification No.:	
City:	Brandy Branch
State:	FL
Company:	JEA - F.O. Storage Tanks
Type of Tank:	Vertical Fixed Roof
Description:	Fuel Oil Storage Tank
Tank Dimensions	
Shell Height (ft):	40.0
Diameter (ft):	65.6
Liquid Height (ft):	39.8
Avg. Liquid Height (ft):	20.0
Volume (gallons):	1000000
Turnovers:	11.1
Net Throughput (gal/yr):	11100000
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft):	0.00
Radius (ft) (Dome Roof):	56.00
Slope (ft/ft) (Cone Roof):	0.0000
Breather Vent Settings	
Vacuum Setting (psig):	-0.03
Pressure Setting (psig):	0.03

Meteorological Data Used in Emission Calculations: Jacksonville, Florida (Avg Atmospheric Pressure = 14.7 psia)

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	69.94	64.36	75.52	68.02	0.0089	0.0075	0.0107	130.000			188.00	Option 3: A=12.1010, B=8907.0

Annual Emission Calculations

Standing Losses (lb):	243.2499
Vapor Space Volume (cu ft):	86154.41
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.038277
Vented Vapor Saturation Factor:	0.988064
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	86154.41
Tank Diameter (ft):	65.6
Vapor Space Outage (ft):	25.49
Tank Shell Height (ft):	40.0
Average Liquid Height (ft):	20.0
Roof Outage (ft):	5.49
Roof Outage (Dome Roof)	
Roof Outage (ft):	5.49
Dome Radius (ft):	56
Shell Radius (ft):	32.8
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Daily Avg. Liquid Surface Temp.(deg. R):	529.61
Daily Average Ambient Temp. (deg. R):	527.67
Ideal Gas Constant R (psia cuft /(lb-mole-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	527.69
Tank Paint Solar Absorptance (Shell):	0.17
Tank Paint Solar Absorptance (Roof):	0.17
Daily Total Solar Insolation Factor (Btu/sqft□day):	1438.00

Vapor Space Expansion Factor

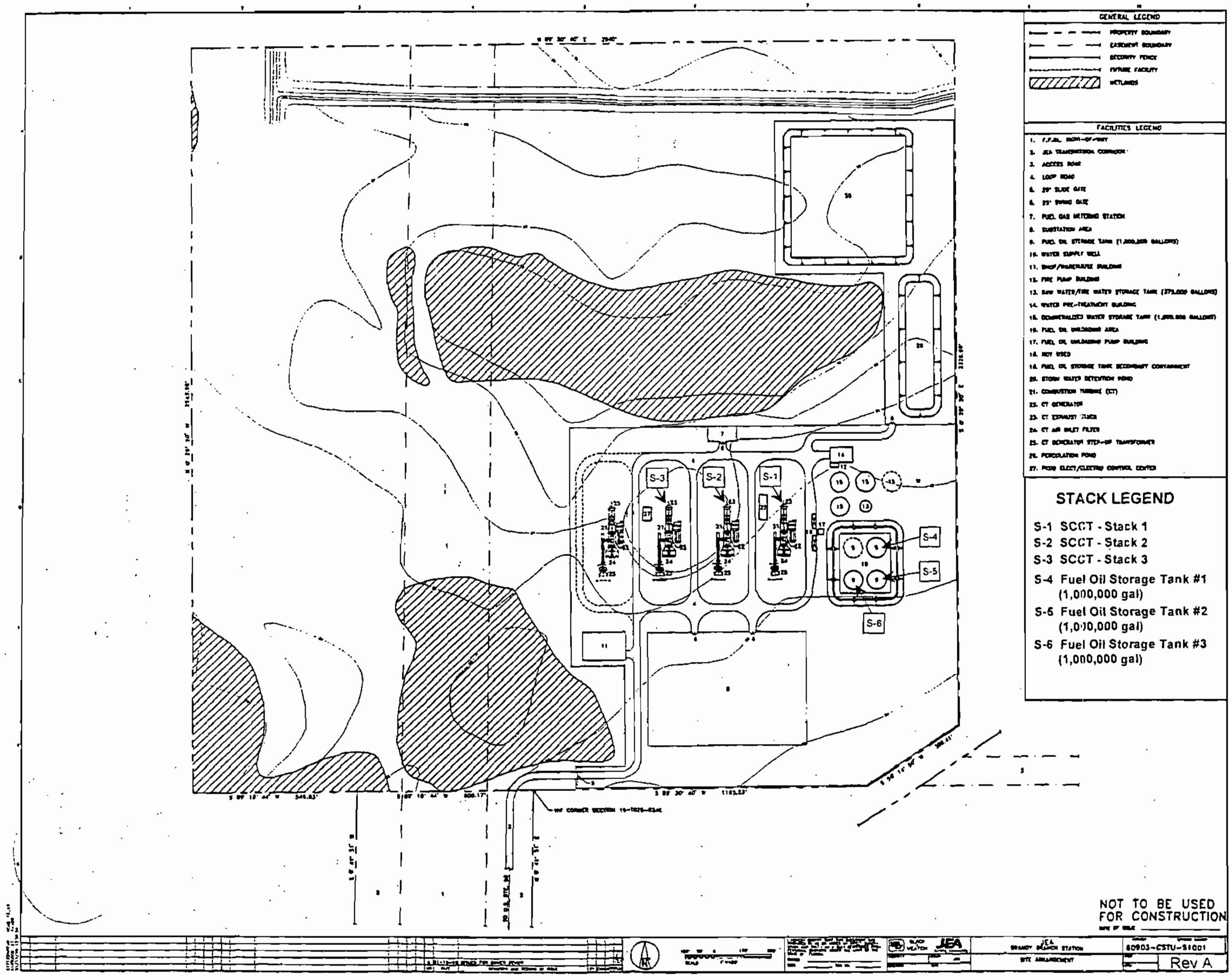
Vapor Space Expansion Factor:	0.038277
Daily Vapor Temperature Range (deg.R):	22.32
Daily Vapor Pressure Range (psia):	0.003180
Breather Vent Press. Setting Range(psia):	0.06
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.007476
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.010655
Daily Avg. Liquid Surface Temp. (deg R):	529.61
Daily Min. Liquid Surface Temp. (deg R):	524.03
Daily Max. Liquid Surface Temp. (deg R):	535.19
Daily Ambient Temp. Range (deg.R):	21.50

Annual Emission Calculations	
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.988064
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Vapor Space Outage (ft):	25.49
Working Losses (lb):	307.2093
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.008942
Annual Net Throughput (gal/yr):	11100000
Turnover Factor:	1.0000
Maximum Liquid Volume (cuft):	134518
Maximum Liquid Height (ft):	39.8
Tank Diameter (ft):	65.6
Working Loss Product Factor:	1.00
Total Losses (lb):	550.46

Annual Emissions Report

Liquid Contents	Losses (lbs.): Standing	Working	Total
Distillate fuel oil no. 2	243.25	307.21	550.46
Total:	243.25	307.21	550.46

Best Available Copy



JEASTACK.SRF

JEA
Jacksonville, Florida
Enveloped Stack Parameters

60903.0030

4000 Hours of natural gas simple cycle operation per year
800 Hous of fuel oil simple cycle operation per year

Last Revised 03/05/99
Date Printed 03/22/99 02:11 PM

NATURAL GAS OPERATION / SHORT TERM / ANNUALIZED (d)

	NATURAL GAS OPERATION			SHORT TERM		ANNUALIZED (d)	
Load	100 Percent						
Turbine	PG7241 (FA)			Representative*		59 Degrees	
Ambient Temperature (F)	95	59	20	100 Pecent Load		100 Pecent Load	
Exit Velocity (ft/s)	147.76	156.75	164.0	147.76 ft/s	45.04 m/s	156.75 ft/s	47.78 ft/s
Exit Temp (F)	1144	1116	1081	1081 F	855.93 K	1116.00 F	875.37 K
Emissions (lb/h)							
NOx (f)	71.20	79.20	84.80	84.8 lb/h	10.68 g/s	36.16 lb/h	4.56 g/s
CO	43.00	48.00	52.00	52 lb/h	6.55 g/s	21.92 lb/h	2.76 g/s
SO2 (a)	0.97	1.07	1.14	1.14 lb/h	0.14 g/s	0.49 lb/h	0.06 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	2.60	2.80	3.00	3 lb/h	0.38 g/s	1.28 lb/h	0.16 g/s
Load	75 Percent						
Turbine	PG7241 (FA)			Representative		59 Degrees	
Ambient Temperature (F)	95	59	20	75 Pecent Load		75 Pecent Load	
Exit Velocity (ft/s)	124.17	129.71	133.13	124.17 ft/s	37.85 m/s	129.71 ft/s	39.54 m/s
Exit Temp (F)	1170	1139	1112	1112 F	873.15 K	1139.00 F	888.15 K
Emissions (lb/h)							
NOx (f)	58.40	63.20	67.20	67.2 lb/h	8.47 g/s	26.86 lb/h	3.84 g/s
CO	36.00	39.00	41.00	41 lb/h	5.17 g/s	17.81 lb/h	2.24 g/s
SO2 (a)	0.79	0.86	0.92	0.92 lb/h	0.12 g/s	0.39 lb/h	0.05 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	2.20	2.2	2.4	2.4 lb/h	0.30 g/s	1.00 lb/h	0.13 g/s
Load	50 Percent						
Turbine	PG7241 (FA)			Representative		59 Degrees	
Ambient Temperature (F)	95	59	20	50 Pecent Load		50 Pecent Load	
Exit Velocity (ft/s)	106.35	110.53	112.68	106.35 ft/s	32.42 m/s	110.53 ft/s	33.69 m/s
Exit Temp (F)	1200	1164	1160	1160 F	899.82 K	1184.00 F	913.15 K
Emissions (lb/h)							
NOx (f)	46.40	50 40	52.60	52.8 lb/h	8.65 g/s	23.01 lb/h	2.90 g/s
CO	30.00	33.00	34.00	34 lb/h	4.28 g/s	15.07 lb/h	1.90 g/s
SO2 (a)	0.64	0.69	0.73	0.73 lb/h	0.09 g/s	0.32 lb/h	0.04 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.82 lb/h	0.10 g/s

FUEL OIL OPERATION / SHORT TERM / ANNUALIZED (d) / Total Annual Dual Fuel Parameters (e)

	FUEL OIL OPERATION			SHORT TERM		ANNUALIZED (d)		Total Annual Dual Fuel Parameters (e)	
Load	100 Percent								
Turbine	PG7241 (FA)			Representative*		59 Degrees			
Ambient Temperature (F)	95	59	20	100 Pecent Load		100 Pecent Load		100 Pecent Load	
Exit Velocity (ft/s)	151.8	161.6	168.04	151.8 ft/s	46.27 m/s	161.60 ft/s	49.26 m/s	156.75 ft/s	47.78 m/s
Exit Temp (F)	1133	1098	1068	1068 F	848.71 K	1098.00 F	865.37 K	1116.00 F	875.37 K
Emissions (lb/h)									
NOx (f)	286.00	318.00	338.00	338 lb/h	42.59 g/s	29.04 lb/h	3.68 g/s	65.21 lb/h	8.22 g/s
CO	59.00	65.00	69.00	69 lb/h	8.69 g/s	5.94 lb/h	0.75 g/s	27.85 lb/h	3.51 g/s
SO2 (a)	88.38	98.21	104.30	104.3 lb/h	13.14 g/s	8.97 lb/h	1.13 g/s	9.46 lb/h	1.19 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.60	3.00	3.00	3 lb/h	0.38 g/s	0.27 lb/h	0.03 g/s	1.55 lb/h	0.20 g/s
Load	75 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	75 Pecent Load		75 Pecent Load		75 Pecent Load	
Exit Velocity (ft/s)	126.43	131.67	135.15	126.43 ft/s	38.54 m/s	131.67 ft/s	40.13 m/s	129.71 ft/s	39.54 m/s
Exit Temp (F)	1200	1194	1183	1183 F	912.59 K	1194.00 F	918.71 K	1139.00 F	888.15 K
Emissions (lb/h)									
NOx (f)	232.00	256.00	271.00	271 lb/h	34.14 g/s	23.38 lb/h	2.95 g/s	52.24 lb/h	6.58 g/s
CO	47.00	50.00	51.00	51 lb/h	6.43 g/s	4.57 lb/h	0.58 g/s	22.37 lb/h	2.82 g/s
SO2 (a)	72.32	79.69	84.44	84.44 lb/h	10.64 g/s	7.28 lb/h	0.92 g/s	7.67 lb/h	0.97 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.20	2.2	2.4	2.4 lb/h	0.30 g/s	0.20 lb/h	0.03 g/s	1.21 lb/h	0.15 g/s
Load	50 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	50 Pecent Load		50 Pecent Load		50 Pecent Load	
Exit Velocity (ft/s)	108.45	112.04	113.42	108.45 ft/s	33.06 m/s	112.04 ft/s	34.15 m/s	110.53 ft/s	33.69 m/s
Exit Temp (F)	1200	1200	1200	1200 F	922.04 K	1200 00 F	922.04 K	1184.00 F	913.15 K
Emissions (lb/h)									
NOx (f)	182.00	199.00	209.00	209 lb/h	26.33 g/s	18.17 lb/h	2.29 g/s	41.19 lb/h	5.19 g/s
CO	74.00	63.00	57.00	74 lb/h	9.32 g/s	5 75 lb/h	0.72 g/s	20.82 lb/h	2.62 g/s
SO2 (a)	57.30	82.70	65.90	65.9 lb/h	8.30 g/s	5.73 lb/h	0.72 g/s	6.04 lb/h	0.76 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.86 lb/h	0.71 g/s
VOC (c)	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.16 lb/h	0.02 g/s	0.99 lb/h	0.12 g/s

NOTE:

(a) SO2 values were calculated based on 0.2 gr/100 scf in the natural gas and #2 distillate fuel oil (0.05% sulfur)
Example Calculations:
Natural gas 100 percent load at 95F = (1,468.9 MBtu/hr)*(lb/23.8 ft^3)*(20,675 Btu/lb)*(0.2gr/100scf)*(1lb/7000gr)*(64SO2/32S)*(10^6Btu/MBtu) = 0.97 lb/hr.
#2 Dist. Fuel Oil 100 percent load @ 95F = (0.05lb S/100lb fuel)*(64 lb SO2/32 lb S)*(7.05 lb fuel/1gal)*(1gal/7.05 lb)*(lb/ 18,550 Btu)*(1,639.4 MBtu/hr)*(10^6 BTU/MBtu) = 88.38 lb/hr.

(b) PM emission values are for front half filterable emissions only.

(c) VOC emissions represent 20% of the UHC emissions.

(d) Annualized emission rate based on specific number of hours of Natural Gas and Fuel Oil operation.

(e) Exit Velocity and Exit Temperature values are from the annualized natural gas operating scenarios.
The emission rate values are annualized @ 59 F based on the number of hour of fuel specific firing.

(f) NOx emission values for natural gas firing are at 12 ppm and 42 ppm for fuel oil firing.

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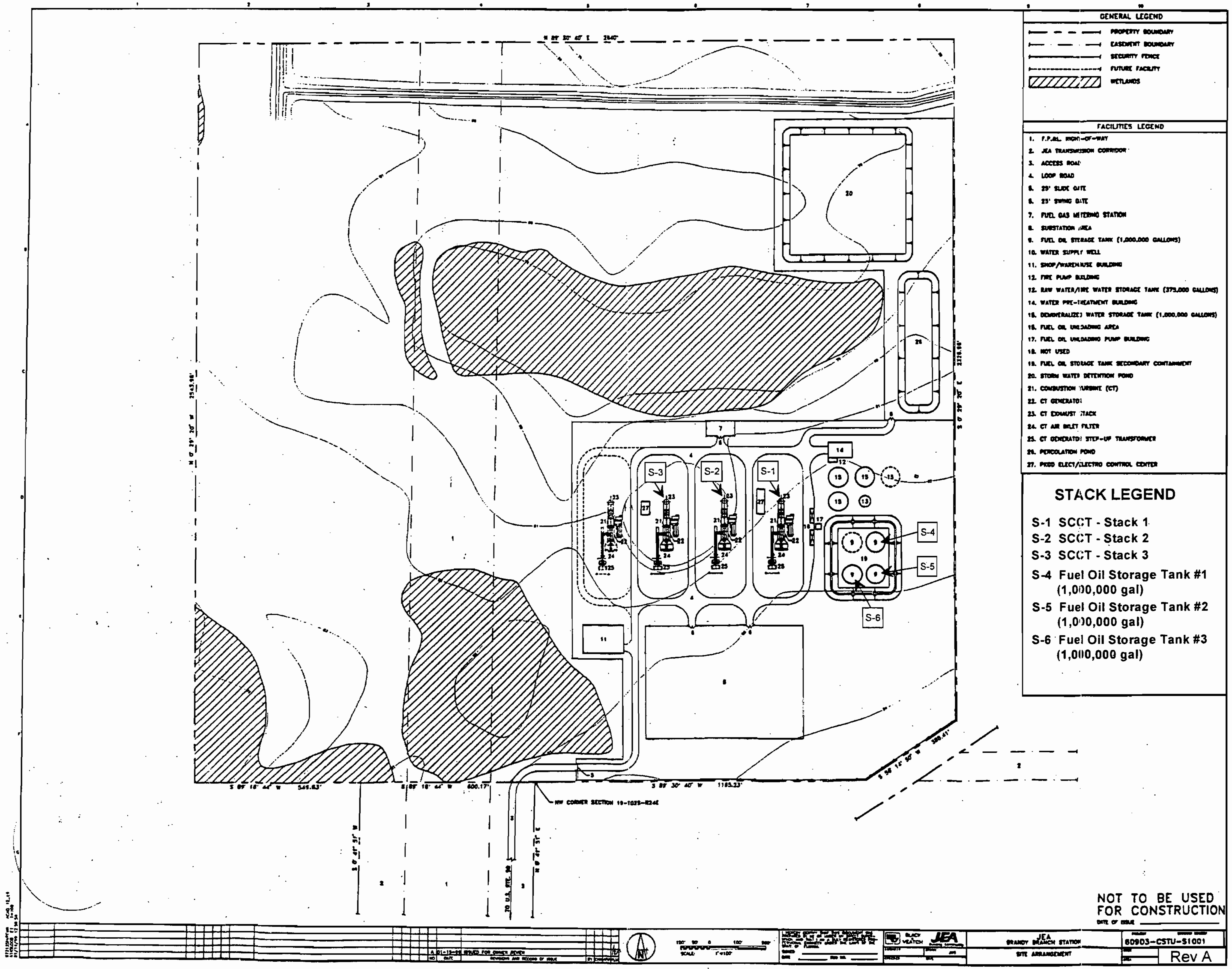

JEASTACK.SRF

JEA
Jacksonville, Florida
Enveloped Stack Parameters

60903.0030

4000 Hours of natural gas simple cycle operation per year
800 Hous of fuel oil simple cycle operation per year

Last Revised 03/05/99
Date Printed 03/22/99 02:11 PM

	NATURAL GAS OPERATION			SHORT TERM		ANNUALIZED (d)	
Load	100 Percent						
Turbine	PG7241 (FA)			Representative*		59 Degrees	
Ambient Temperature (F)	95	59	20	100 Pecent Load		100 Pecent Load	
Exit Velocity (ft/s)	147.76	156.75	164.0	147.76 ft/s	45.04 m/s	156.75 ft/s	47.78 ft/s
Exit Temp (F)	1144	1116	1081	1081 F	855.93 K	1116.00 F	875.37 K
Emissions (lb/h)							
NOx (f)	71.20	79.20	84.80	84.8 lb/h	10.68 g/s	36.16 lb/h	4.56 g/s
CO	43.00	48.00	52.00	52 lb/h	6.55 g/s	21.92 lb/h	2.76 g/s
SO2 (a)	0.97	1.07	1.14	1.14 lb/h	0.14 g/s	0.49 lb/h	0.06 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	2.60	2.80	3.00	3 lb/h	0.38 g/s	1.28 lb/h	0.16 g/s
Load	75 Percent						
Turbine	PG7241 (FA)			Representative		59 Degrees	
Ambient Temperature (F)	95	59	20	75 Pecent Load		75 Pecent Load	
Exit Velocity (ft/s)	124.17	129.71	133.13	124.17 ft/s	37.85 m/s	129.71 ft/s	39.54 m/s
Exit Temp (F)	1170	1139	1112	1112 F	873.15 K	1139.00 F	888.15 K
Emissions (lb/h)							
NOx (f)	58.40	63.20	67.20	67.2 lb/h	8.47 g/s	28.86 lb/h	3.64 g/s
CO	36.00	39.00	41.00	41 lb/h	5.17 g/s	17.81 lb/h	2.24 g/s
SO2 (a)	0.79	0.86	0.92	0.92 lb/h	0.12 g/s	0.39 lb/h	0.05 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	2.20	2.2	2.4	2.4 lb/h	0.30 g/s	1.00 lb/h	0.13 g/s
Load	50 Percent						
Turbine	PG7241 (FA)			Representative		59 Degrees	
Ambient Temperature (F)	95	59	20	50 Pecent Load		50 Pecent Load	
Exit Velocity (ft/s)	106.35	110.53	112.68	106.35 ft/s	32.42 m/s	110.53 ft/s	33.69 m/s
Exit Temp (F)	1200	1184	1160	1160 F	899.82 K	1184.00 F	913.15 K
Emissions (lb/h)							
NOx (f)	46.40	50.40	52.80	52.8 lb/h	6.65 g/s	23.01 lb/h	2.90 g/s
CO	30.00	33.00	34.00	34 lb/h	4.28 g/s	15.07 lb/h	1.90 g/s
SO2 (a)	0.64	0.69	0.73	0.73 lb/h	0.09 g/s	0.32 lb/h	0.04 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.82 lb/h	0.10 g/s

	FUEL OIL OPERATION			SHORT TERM		ANNUALIZED (d)		Total Annual Dual Fuel Parameters (e)	
Load	100 Percent								
Turbine	PG7241 (FA)			Representative*		59 Degrees			
Ambient Temperature (F)	95	59	20	100 Pecent Load		100 Pecent Load		100 Pecent Load	
Exit Velocity (ft/s)	151.8	161.6	168.04	151.8 ft/s	46.27 m/s	161.60 ft/s	49.26 m/s	156.75 ft/s	47.78 m/s
Exit Temp (F)	1133	1098	1068	1068 F	848.71 K	1098.00 F	865.37 K	1116.00 F	875.37 K
Emissions (lb/h)									
NOx (f)	286.00	318.00	338.00	338 lb/h	42.59 g/s	29.04 lb/h	3.66 g/s	65.21 lb/h	8.22 g/s
CO	59.00	65.00	69.00	69 lb/h	8.69 g/s	5.94 lb/h	0.75 g/s	27.85 lb/h	3.51 g/s
SO2 (a)	88.38	98.21	104.30	104.3 lb/h	13.14 g/s	8.97 lb/h	1.13 g/s	9.46 lb/h	1.19 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.60	3.00	3.00	3 lb/h	0.38 g/s	0.27 lb/h	0.03 g/s	1.55 lb/h	0.20 g/s
Load	75 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	75 Pecent Load		75 Pecent Load		75 Pecent Load	
Exit Velocity (ft/s)	126.43	131.67	135.15	126.43 ft/s	38.54 m/s	131.67 ft/s	40.13 m/s	129.71 ft/s	39.54 m/s
Exit Temp (F)	1200	1194	1183	1183 F	912.59 K	1194.00 F	918.71 K	1139.00 F	888.15 K
Emissions (lb/h)									
NOx (f)	232.00	256.00	271.00	271 lb/h	34.14 g/s	23.38 lb/h	2.95 g/s	52.24 lb/h	6.58 g/s
CO	47.00	50.00	51.00	51 lb/h	6.43 g/s	4.57 lb/h	0.58 g/s	22.37 lb/h	2.82 g/s
SO2 (a)	72.32	79.69	84.44	84.44 lb/h	10.64 g/s	7.28 lb/h	0.92 g/s	7.67 lb/h	0.97 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.20	2.2	2.4	2.4 lb/h	0.30 g/s	0.20 lb/h	0.03 g/s	1.21 lb/h	0.15 g/s
Load	50 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	50 Pecent Load		50 Pecent Load		50 Pecent Load	
Exit Velocity (ft/s)	108.45	112.04	113.42	108.45 ft/s	33.06 m/s	112.04 ft/s	34.15 m/s	110.53 ft/s	33.69 m/s
Exit Temp (F)	1200	1200	1200	1200 F	922.04 K	1200.00 F	922.04 K	1184.00 F	913.15 K
Emissions (lb/h)									
NOx (f)	182.00	199.00	209.00	209 lb/h	26.33 g/s	18.17 lb/h	2.29 g/s	41.19 lb/h	5.19 g/s
CO	74.00	63.00	57.00	74 lb/h	9.32 g/s	5.75 lb/h	0.72 g/s	20.82 lb/h	2.62 g/s
SO2 (a)	57.30	62.70	65.90	65.9 lb/h	8.30 g/s	5.73 lb/h	0.72 g/s	6.04 lb/h	0.76 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.16 lb/h	0.02 g/s	0.99 lb/h	0.12 g/s

NOTE:

(a) SO2 values were calculated based on 0.2 gr/100 scf in the natural gas and #2 distillate fuel oil (0.05% sulfur)
Example Calculations:
Natural gas 100 percent load at 95F = (1,468.9 MBtu/hr)*(lb/23.8 ft^3)*(20,675 Btu/lb)*(0.2gr/100scf)*(1lb/7000gr)*(64SO2/32S)*(10^6Btu/MBtu) = 0.97 lb/hr.
#2 Dist. Fuel Oil 100 percent load @ 95F = (0.05lb S/100lb fuel)*(64 lb SO2/32 lb S)*(7.05 lb fuel/1gal)*(1gal/7.05 lb)*(lb/ 18,550 Btu)*(1,639.4 MBtu/hr)*(10^6 BTU/MBtu) = 88.38 lb/hr.

(b) PM emission values are for front half filterable emissions only.

(c) VOC emissions represent 20% of the UHC emissions.

(d) Annualized emission rate based on specific number of hours of Natural Gas and Fuel Oil operation.

(e) Exit Velocity and Exit Temperature values are from the annualized natural gas operating scenarios.
The emission rate values are annualized @ 59 F based on the number of hour of fuel specific firing.

(f) NOx emission values for natural gas firing are at 12 ppm and 42 ppm for fuel oil firing.

JEA 60903.0030
Jacksonville, Florida
Enveloped Stack Parameters

4000 Hours of natural gas simple cycle operation per year
800 Hous of fuel oil simple cycle operation per year

Last Revised 03/05/99
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NATURAL GAS OPERATION — SHORT TERM — ANNUALIZED (d)

Load	100 Percent						
Turbine	PG7241 (FA)			Representative*		59 Degrees	
Ambient Temperature (F)	95	59	20	100 Pecent Load		100 Pecent Load	
Exit Velocity (ft/s)	148	157	164.0	148 ft/s	45.04 m/s	156.75 ft/s	47.78 ft/s
Exit Temp (F)	1144	1116	1081	1081 F	855.93 K	1116.00 F	875.37 K
Emissions (lb/h)							
NOx (f)	71.20	79.20	84.80	85 lb/h	10.68 g/s	36.16 lb/h	4.56 g/s
CO	43.00	48.00	52.00	52 lb/h	6.55 g/s	21.92 lb/h	2.76 g/s
SO2 (a)	0.97	1.07	1.14	1 lb/h	0.14 g/s	0.49 lb/h	0.06 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	2.60	2.80	3.00	3 lb/h	0.38 g/s	1.28 lb/h	0.16 g/s

Load	75 Percent						
Turbine	PG7241 (FA)			Representative		59 Degrees	
Ambient Temperature (F)	95	59	20	75 Pecent Load		75 Pecent Load	
Exit Velocity (ft/s)	124	130	133	124 ft/s	37.85 m/s	129.71 ft/s	39.54 m/s
Exit Temp (F)	1170	1139	1112	1112 F	873.15 K	1139.00 F	888.15 K
Emissions (lb/h)							
NOx (f)	58.40	63.20	67.20	67 lb/h	8.47 g/s	28.86 lb/h	3.64 g/s
CO	36.00	39.00	41.00	41 lb/h	5.17 g/s	17.81 lb/h	2.24 g/s
SO2 (a)	1	0.86	0.92	1 lb/h	0.12 g/s	0.39 lb/h	0.05 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	2.20	2	2	2 lb/h	0.30 g/s	1.00 lb/h	0.13 g/s

Load	50 Percent						
Turbine	PG7241 (FA)			Representative		59 Degrees	
Ambient Temperature (F)	95	59	20	50 Pecent Load		50 Pecent Load	
Exit Velocity (ft/s)	106	111	113	106 ft/s	32.42 m/s	110.53 ft/s	33.69 m/s
Exit Temp (F)	1200	1184	1160	1160 F	899.82 K	1184.00 F	913.15 K
Emissions (lb/h)							
NOx (f)	46.40	50.40	52.80	53 lb/h	6.65 g/s	23.01 lb/h	2.90 g/s
CO	30.00	33.00	34.00	34 lb/h	4.28 g/s	15.07 lb/h	1.90 g/s
SO2 (a)	1	1	1	1 lb/h	0.09 g/s	0.32 lb/h	0.04 g/s
PM (b)	9.00	9.00	9.00	9 lb/h	1.13 g/s	4.11 lb/h	0.52 g/s
VOC (c)	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.82 lb/h	0.10 g/s

FUEL OIL OPERATION — SHORT TERM — ANNUALIZED (d) — Total Annual Dual Fuel Parameters (e)

Load	100 Percent								
Turbine	PG7241 (FA)			Representative*		59 Degrees			
Ambient Temperature (F)	95	59	20	100 Pecent Load		100 Pecent Load		100 Pecent Load	
Exit Velocity (ft/s)	152	162	168.04	152 ft/s	46.27 m/s	161.60 ft/s	49.26 m/s	156.75 ft/s	47.78 m/s
Exit Temp (F)	1133	1098	1068	1068 F	848.71 K	1098.00 F	865.37 K	1116.00 F	875.37 K
Emissions (lb/h)									
NOx (f)	286.00	318.00	338.00	338 lb/h	42.59 g/s	29.04 lb/h	3.66 g/s	65.21 lb/h	8.22 g/s
CO	59.00	65.00	69.00	69 lb/h	8.69 g/s	5.94 lb/h	0.75 g/s	27.85 lb/h	3.51 g/s
SO2 (a)	88.38	98.21	104.30	104 lb/h	13.14 g/s	8.97 lb/h	1.13 g/s	9.46 lb/h	1.19 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.60	3.00	3.00	3 lb/h	0.38 g/s	0.27 lb/h	0.03 g/s	1.55 lb/h	0.20 g/s

Load	75 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	75 Pecent Load		75 Pecent Load		75 Pecent Load	
Exit Velocity (ft/s)	126.43	132	135	126 ft/s	38.54 m/s	131.67 ft/s	40.13 m/s	129.71 ft/s	39.54 m/s
Exit Temp (F)	1200	1194	1183	1183 F	912.59 K	1194.00 F	918.71 K	1139.00 F	888.15 K
Emissions (lb/h)									
NOx (f)	232.00	256.00	271.00	271 lb/h	34.14 g/s	23.38 lb/h	2.95 g/s	52.24 lb/h	6.58 g/s
CO	47.00	50.00	51.00	51 lb/h	6.43 g/s	4.57 lb/h	0.58 g/s	22.37 lb/h	2.82 g/s
SO2 (a)	72.32	79.69	84.44	84 lb/h	10.64 g/s	7.28 lb/h	0.92 g/s	7.67 lb/h	0.97 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	2.20	2	2	2 lb/h	0.30 g/s	0.20 lb/h	0.03 g/s	1.21 lb/h	0.15 g/s

Load	50 Percent								
Turbine	PG7241 (FA)			Representative		59 Degrees			
Ambient Temperature (F)	95	59	20	50 Pecent Load		50 Pecent Load		50 Pecent Load	
Exit Velocity (ft/s)	108.45	112	113	108 ft/s	33.06 m/s	112.04 ft/s	34.15 m/s	110.53 ft/s	33.69 m/s
Exit Temp (F)	1200	1200	1200	1200 F	922.04 K	1200.00 F	922.04 K	1184.00 F	913.15 K
Emissions (lb/h)									
NOx (f)	182.00	199.00	209.00	209 lb/h	26.33 g/s	18.17 lb/h	2.29 g/s	41.19 lb/h	5.19 g/s
CO	74.00	63.00	57.00	74 lb/h	9.32 g/s	5.75 lb/h	0.72 g/s	20.82 lb/h	2.62 g/s
SO2 (a)	57.30	62.70	65.90	66 lb/h	8.30 g/s	5.73 lb/h	0.72 g/s	6.04 lb/h	0.76 g/s
PM (b)	17.00	17.00	17.00	17 lb/h	2.14 g/s	1.55 lb/h	0.20 g/s	5.66 lb/h	0.71 g/s
VOC (c)	1.80	1.80	2.00	2 lb/h	0.25 g/s	0.16 lb/h	0.02 g/s	0.99 lb/h	0.12 g/s

NOTE:

(a) SO2 values were calculated based on 0.2 gr/100 scf in the natural gas and #2 distillate fuel oil (0.05% sulfur)
Example Calculations:
Natural gas 100 percent load at 95F = (1,468.9 MBtu/hr)*(lb/23.8 ft^3)*(20,675 Btu/lb)*(0.2gr/100scf)*(1lb/7000gr)*(64SO2/32S)*(10^6Btu/MBtu) = 0.97 lb/hr.
#2 Dist. Fuel Oil 100 percent load @ 95F = (0.05lb S/100lb fuel)*(64 lb SO2/32 lb S)*(7.05 lb fuel/1gal)*(1gal/7.05 lb)*(lb/ 18,550 Btu)*(1,639.4 MBtu/hr)*(10^6 BTU/MBtu) = 88.38 lb/hr.

(b) PM emission values are for front half filterable emissions only.

(c) VOC emissions represent 20% of the UHC emissions.

(d) Annualized emission rate based on specific number of hours of Natural Gas and Fuel Oil operation.

(e) Exit Velocity and Exit Temperature values are from the annualized natural gas operating scenarios.
The emission rate values are annualized @ 59 F based on the number of hour of fuel specific firing.

(f) NOx emission values for natural gas firing are at 12 ppm and 42 ppm for fuel oil firing.

Z 333 618 154

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to: Bert Gianazza	
Street & Number: JEA	
Post Office, State, & ZIP Code: Jax Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: 5-26-99 0310485-001-AC PSD-Fl-267	

PS Form **3800**, April 1995

Fold at line over top of envelope to the right of the return address

Is your **RETURN ADDRESS** completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Bert Gianazza, PE
JEA
21 W. Church St.
Jacksonville, Fl
32202-3139

4a. Article Number
Z 333 618 154

4b. Service Type
- ☐ Registered
- ☒ Certified
- ☐ Express Mail
- ☐ Insured
- ☐ Return Receipt for Merchandise
- ☐ COD

7. Date of Delivery
5-28-99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X D. Moe

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-97-B-0179 **Domestic Return Receipt**

Z 333 618 113

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Bert Gianazza	
Street & Number JEA	
Post Office, State, & ZIP Code Jax Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 7-21-99 0310485-001-AC PSD-F1-267	

PS Form **3800**, April 1995

return address
Fold at line over top of envelope to

Is your **RETURN ADDRESS** completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Bert Gianazza, PE
JEA
21 W. Church St.
Jacksonville, Fl
32202-3139

4a. Article Number
Z 333 618 113

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery 7-23-99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X D. Rose

PS Form **3811,** December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 333 618 123

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to Doug Neeley	
Street & Number EPA - Region 4	
Post Office, State, & ZIP Code Atlanta GA	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date JEA Brandy PSD-F1-267 0310485-001-AC	8-12-99

PS Form **3800**, April 1995

Is your **RETURN ADDRESS** completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Doug Neeley, Chief
Air, Radiation Tech. Br.
US EPA Region 4
61 Forsyth St.
Atlanta, GA 30303

4a. Article Number
Z 333 618 123

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery

5. Received By: *(Print Name)* JOYCE EVANS

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)* AUG 16 1999
X

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 333 618 124

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail (See reverse)

Sent to Walter Bussels	
Street & Number JEA - BB	
Post Office, State, & ZIP Code Jax Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 8-12-99 0310485-001-AC PSD-F1-267	

PS Form **3800**, April 1995

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Walter Bussels
JEA - Brandy Branch
21 W. Church St.
Jacksonville, Fl
32202-3139

4a. Article Number
Z 333 618 124

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
8-16-99

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X D. Croc

PS Form **3811,** December 1994 102595-98-B-0229 Domestic Return Receipt

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

RECEIVED

AUG 30 1999

BUREAU OF AIR REGULATION

FLORIDA PUBLISHING COMPANY

Publisher

JACKSONVILLE, DUVAL COUNTY, FLORIDA

STATE OF FLORIDA
COUNTY OF DUVAL

Before the undersigned authority personally appeared Steven L. Smith who on oath says that he is Legal Advertising Representative of The Florida Times-Union, a daily newspaper published at Jacksonville in Duval County, Florida; that the attached copy of advertisement, being a Legal Advertisement

in the matter of Public Notice of Intent to Issue Air Construction Permit

in the ______ Court,

was published in THE FLORIDA TIMES-UNION in the issues of August 23, 1999

Affiant further says that the said The Florida Times-Union is a newspaper published at Jacksonville, in said Duval County, Florida, and that the said newspaper has heretofore been continuously published in said Duval County, Florida, The Florida Times-Union each day, has been entered as second class mail matter at the postoffice in Jacksonville, in said Duval County, Florida, for a period of one year next preceeding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in said newspaper.

Sworn to and subscribed before me this 25th day of August A.D. 1999

Vera Janie Likens

Notary Public,
State of Florida at Large.

Steven L. Smith

My Commission Expires ....

Vera Janie Likens
Commission # CC 547806
Expires Jun. 1, 2000
Bonded Thru
Atlantic Bonding Co., Inc.

DA 444

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 0310485-00-AC (PSD-FL-267)
JEA Brandy Branch facility Units 1-3
Duval County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to JEA. The permit is to construct three nominal 170 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine-electrical generators with 90-foot stacks and three 1 million gallon fuel storage tanks for the proposed Brandy Branch Facility near Baldwin City, Duval County. A Best Available Control Technology (BACT) determination was required for sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), nitrogen oxides (NO_x), Sulfuric acid mist (SAM), and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are JEA, 21 West Church Street, Jacksonville, Florida 32202.

The new units will be General Electric nominal 170 MW PG7241FA combustion turbines-electrical generators. The units will operate in simple cycle mode and intermittent duty. The units will operate primarily on natural gas and will be permitted to operate no mare than 4750 hours per year of which no more than 750 hours per year and 16 hours per day will be using 0.05 percent sulfur distillate fuel oil.

NO_x emissions will be controlled by Dry LawNO_x (DLN-2.6) combustars. The units must achieve the manufacturer's initial "new and clean" performance guarantee of 9 parts per million by volume at 15 percent oxygen (ppm) and meet a continuous emission limit based on 10.5 ppm. NO_x will be controlled to 42 ppm by wet injection when firing fuel oil. Sulfuric acid mist, SO_2, and PM/PM10 will be limited by use of clean fuels. Emissions of VOC and CO will be controlled by good combustion practices.

The maximum emissions in per tons per year based on the original application are summarized below. All emissions will be somewhat lower as a result of the Department's proposed BACT determination.

Pollutant	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	74.4	25/15
CO	366.2	100
NO_x	857.7	40
VOC	21	40
SO_2	124.3	40
Sulfuric Acid Mist	15.2	7

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class II significant impact levels. PSD Class I significant impact levels are exceeded for sulfur dioxide, therefore a Class I PSD increment analysis for SO_2 was conducted. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any AAQS or PSD increment.

Concurrent with the startup of the new facility, JEA will shutdown the Southside facility located at 801 Colorado Avenue in Jacksonville, Florida. The Southside emissions along with the net effect of these actions is shown below:

Pollutant	Southside Emissions	Net Emissions
PM/PM_{10}	74.9	(0.4)
CO	54.2	312
NO_x	735.5	122.2
SO_2	902.3	(778)

The Department will accept written comments and requests for a public hearing (meeting) concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of "Public Notice of Intent to Issue PSD 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 FINAL Permit, in accordance with the conditions of the DRAFT Permit, 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 DRAFT Permit issuance action for a period of 30 (thirty) days from the date of publication of this Notice. Written comments should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, mail Station #5005, Tallahassee, Florida, 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in this DRAFT Permit, the Department shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

The Department will issue FINAL Permit with the conditions of the DRAFT Permit subject to the exceptions noted above unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. The procedures for petitioning for a hearing are set forth below. Mediation is not available for the proposed action.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 850/488-9370, fax; 850/487-4938. Petitions 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. A petitioner must 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 28-5.207 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 as well as the rules and statutes which entitle the petitioner to relief; and (f) A demand for relief.

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 of intent. 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:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department Environmental Protection
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, Florida 32256-7590
Telephone: 904/448-4300
Fax: 904/448-4366

Jacksonville Regulatory and Environmental Services Department
Suite 225, 117 W. Duval Street
Jacksonville, Florida 32202
Telephone: 904/630-3484
Fax: 904/630-6338

The complete project file includes the application, technical evaluation, 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, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850-488-0114, for additional information.

Z 031 391 960

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to Walter Bussells	
Street & Number JEA	
Post Office, State, & ZIP Code Jacksonville Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 0310485-001-AC P50-F1-267	10-14-99

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
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I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Walter Bussells
Jacksonville Electric A.
21 W. Church St.
Jacksonville, Fl
32202-3139

4a. Article Number
Z 031 391 960

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
10-18-9

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X

PS Form **3811**, December 1994 102595-98-B-0229 Domestic R

Thank you for using Return Receipt Service.