P.E. Certification Statement

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

DEP File No.: 0310485-003-AC (PSD-FL-310)
Facility ID No.: 0310485

Project: PSD 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).

Cleve Holladay and I conducted this review.

(Seal)

Michael P. Halpin, P.E.
Registration Number: 31970

4/20/07
Date

Permitting Authority:
Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
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Tallahassee, Florida 32399-2400

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STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. Walter P. Bussells, Managing Director and CEO JEA 21 West Church Street Jacksonville, FL 32234	DEP File 0310485-003-AC (PSD-310) Brandy Branch Generating Facility Duval County

Enclosed is the Final Permit Number PSD-FL-310. This permit authorizes the applicant to construct a nominal 540 megawatt (MW) Combined Cycle generating unit consisting of: two nominal 170 MW, stationary (existing) combustion turbine-electrical generators fired solely on pipeline quality natural gas (with oil capability) and equipped with evaporative coolers; two (new) supplementally-fired heat recovery steam generators (HRSGs) and associated 190-foot stacks; one (new) nominal 200 MW steam electrical generator; one (new) freshwater cooling tower; two (new) selective catalytic reduction units including ancillary equipment and ammonia storage. The existing facility is known as the Brandy Branch Generating Facility in Duval County. This permit is issued pursuant to Chapter 403, Florida Statutes and 40CFR52.21.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

In addition to the appeal process described above, federal appeals procedures concerning this PSD permit are outlined in 40CFR 124.19, which is attached. Any person who filed comments on the draft permit may petition the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments on the draft permit may petition for administrative review only to the extent of the changes from the draft to the final permit decision.

The petition must be filed with the Environmental Appeals Board within 30 days of issuance of this Notice. Petitions may be addressed to the Environmental Appeals Board, MC 1103B, U.S. Environmental Protection Agency, 401 M Street, Washington, D.C. 20460. Further details are available at www.epa.gov/eab.

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 NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail* and copies were mailed by U.S. Mail before the close of business on 3/29/02 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
Charles J. Schutty, P.E., Black & Veatch
Mr. Hamilton S. Oven, DEP-Siting

Clerk Stamp

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

Victoria Gibson March 29, 2002
(Clerk) (Date)

FINAL DETERMINATION

JEA
Brandy Branch Combined Cycle Conversion
DEP File No. PA 00-43, PSD-FL-310

The Department distributed a public notice package on April 26, 2001 to allow the applicant to convert two simple cycle combustion turbines to combined cycle at the recently permitted Brandy Branch Facility, Duval County. The Public Notice of Intent to Issue was published in the Florida Times-Union on May 18, 2001.

COMMENTS/CHANGES

Comments were received from the EPA dated July 19, 2001.

Comments on the draft permit were received from the applicant by letter dated June 14, 2001.

All comments shown below are italicized and are from JEA unless otherwise indicated.

Pursuant to notice, the Division of Administrative Hearings, by its duly designated Administrative Law Judge, J. L. Johnston, conducted a formal site certification hearing (Case No. 00-5120) in this proceeding on December 4, 2001 in Baldwin, Florida. It was recommended that the Siting Board grant full and final certification to JEA, under Section 403, Part II, Florida Statutes, for the location, construction, and operation of Brandy Branch, representing two combined cycle units, as described in the Site Certification Application and the evidence presented at the certification hearing.

On March 12, 2002 the Siting Board concurred with the Administrative Law Judge's recommendation and authorized issuance of related permits via its Final Order.

DRAFT Permit Cover Page:

JEA requests that the permit expiration be set at December 31, 2005 for the reasons mentioned below.

- *The facility is subject to the Florida Power Plant Siting Act and the Air Construction Permit, though finalized, will not be effective until after the Site Certification is issued.*
- *Construction is expected to last for approximately 2 years.*

After the completion of construction and initial startup, an additional 180 days are required to submit an application for a Title V Air Operating Permit.

JEA requests that the heights of the two HRSG stacks (190 ft) that will be constructed as part of the combined cycle conversion of the existing Brandy Branch units EU-002 and EU-003, and the evaporative coolers on each CTG/HRSG be reflected in the project description.

RESPONSE: The Cover Page will be revised.

DRAFT Permit Facility Description:

To help prevent the potential confusion and conflict caused by two separate PSD permits for Units 2 and 3, JEA suggests that clarifying language be added.

RESPONSE: The Facility Description will be revised.

DRAFT Permit General and Administrative Conditions:

The language of Condition 7 is obsolete and should be deleted since the project is now being converted.

RESPONSE: The purpose of this Condition is to highlight those activities, which commonly trigger a PSD applicability determination for a clear understanding by all parties. Since many of these items (e.g.

hours of oil firing, increases in heat input limits, etc.) represent possible future requests for this project, the Condition should remain intact.

If construction is commenced within 18 months of issuance of the permit and such construction has been continuous, a reconsideration of BACT should not be required. Neither EPA's nor DEP's rules require a reconsideration of BACT due to an extension of the permit expiration date. JEA therefore requests that this portion of Condition 8 be deleted.

RESPONSE: The purpose of this related portion of Condition 8 is to ensure that the permittee understands that the Department will consider the diligence of construction activities in evaluating extension requests. Furthermore, should the Department determine that a lack of diligence exists concerning a particular extension request (or series thereof), the Department may reconsider the BACT.

JEA has already submitted an Acid Rain Permit application for the Brandy Branch facility. While a revision addressing the monitoring plan changes for Units 2 and 3 will be submitted in the future, there should be no requirement to make this submittal 24 months in advance of operation of the "new unit." Omission of Condition 9 will not affect applicability of the appropriate Acid Rain Program requirements.

RESPONSE: Condition 9 will be modified to reflect a requirement to submit a revised Acid Rain Permit.

Because the Title V permit for the three CTs should be issued by the time this PSD permit is final, it will be appropriate to file for a revision rather than an initial Title V application.

RESPONSE: Condition 10 will be modified accordingly.

DRAFT Permit Specific Conditions:

There are two duct burners proposed and permitted in the Brandy Branch combined cycle conversion project, one in each HRSG. The actual maximum heat input of each duct burner is 85 MMBtu/hr (HHV Natural Gas), for a total of 170 MMBtu/hr (HHV) for the project. Based on the size of each duct burner, the applicable NSPS regulation is Subpart Dc. JEA requests that this correction be made throughout the Technical Evaluation and Permit Conditions

RESPONSE: The Department will make related permit changes to Specific Conditions 4, 9, 18 and 20.

The permitting note language regarding the heat input limitation was included in the original PSD permit for these units and appears to have been inadvertently omitted. JEA requests that this language be included to clarify the purpose of the heat input rates being listed in the permit.

RESPONSE: The Department will make related permit changes to Specific Conditions 8 and 9.

The use of oil should not be unnecessarily restricted on a per-unit basis. The combined oil use for the two units will result in the same environmental impact but offer more operational flexibility for JEA. JEA therefore requests that the oil usage restriction be changed from 288 hours per unit to 576 hours for both units combined.

RESPONSE: This permit will not incorporate oil firing. This is further addressed below.

BACT does not require that numeric standards be established when a "design" standard is appropriate, as in the case of cooling towers. Because it is not possible to accurately determine the precise drift elimination efficiency of cooling towers, a design requirement without a numeric permit limit is *appropriate. JEA therefore respectfully requests that the numeric limit in this condition be deleted. Otherwise, confusion as to periodic monitoring requirements could arise in the future.*

RESPONSE: This PSD permit triggered a review for PM_{10}, with annual emissions exceeding 185 TPY although modeling showed 24-hour emissions at 4.8 $\mu g/m^3$, which is just under the SIL of 5 $\mu g/m^3$. Accordingly, the Department conducted a BACT Review, and established a control technology with appropriate emission limits for the PM_{10} emitting sources. The Department has determined that the cooling tower recirculation flowrate represents the means by which this BACT Determined limit can be validated and has established a similar requirement within several permits.

As in the original PSD permit for Units 2 and 3, a 24-hour block average is appropriate for NOx emissions. NOx emissions are regulated under the PSD program because of the annual nitrogen dioxide standard and because NOx is a precursor to ozone, which is not a short-term but rather a longer-term issue. In fact, the NSPS standards typically establish a 30-day rolling average period for NOx, as does Section 403.0872(13)(b), Florida Statutes, which provides that for emission units subject to continuous monitoring requirements of the Acid Rain Program (as these units are), compliance with NOx limits shall be demonstrated based on a 30-day rolling average. In addition, Brandy Branch Units 2 and 3 will be intermediate load units (rather than base load units) and subject to load changing conditions on a routine basis. The NOx emissions from Units 2 and 3 are not expected to be as consistent as they would if the units were simply run at full load operations at all times. The longer, 24-hour averaging period is therefore needed to ensure continuous compliance with the emission limits. In addition, no environmental rationale for a 3-hour averaging period was provided under the BACT preliminary determination and annual emissions are not affected. JEA therefore respectfully requests that the 3-hour averaging time be changed to a 24-hour averaging period (while firing natural gas), which is consistent with the prior permit yet much more stringent than provided under the Florida Statutes.

RESPONSE: The Department has established a 3.5 ppmvd emission limit based upon a 3-hour averaging time as BACT, as has been done in previous recent Determinations. As noted in EPA Region 4 correspondence dated June 18, 2001 on a similar project subject to the PPSA, "Condition 21 in the draft permit (page 8 of 20) specifies NO_X emission limits on a 3-hour block average basis. A compliance averaging period of 3 hours for NO_X emissions has been specified in many combined cycle combustion turbine permits and is appropriate."

Ammonia is not a regulated air pollutant under the Department's air rules, and the Department therefore lacks the authority to establish a numeric emission limit in this permit for ammonia emissions. In addition, the performance of the SCR system can be accurately measured through the use of the continuous emissions monitoring system for NOx. An ammonia slip limit is therefore unnecessary for determining compliance with the NOx limit. Further, no environmental rationale was provided in the preliminary determination for this limit. These units are located in a rural, lightly populated area, and so there is less human health risk associated with the use of aqueous ammonia. JEA therefore respectfully requests that this part of the condition be deleted

RESPONSE: The Department has established a 5-ppmvd ammonia slip emission limit as BACT associated with the SCR, based upon submittals from applicants contending that ammonia-related particulate emissions may result. The Department does not require a continuous measurement of ammonia slip, but rather requires that the permittee be able to provide an immediate indication of ammonia slip if required to do so by the appropriate representative of RESD or DEP. Numeric ammonia slip values are routinely included in Florida's PSD permits.

Carbon monoxide is regulated under the PSD program because of the ambient air quality standard that was established by EPA. The computer modeling performed by JEA indicated that the projected CO air quality impact concentration from these units will be more than 25 times below the significance level for the ambient air quality standard of CO, making the proposed limit of 14 ppmvd extremely protective of human health. An annual stack test should therefore be sufficient to determine compliance with the CO limit. This stack test could be conducted while the NOx RATA is performed each year. The capital and operational costs of operating a CO monitor along with the additional record keeping and reporting burdens associated with a CEM are not justified. JEA therefore respectfully requests that the CO CEM requirement be deleted from this and related conditions.

RESPONSE: This PSD permit triggered a review for CO, with annual emissions exceeding the significant emission rate of 100 TPY nearly five-fold. Accordingly, the Department conducted a BACT Review, and established good combustion as the control technology with an emission limit of 14 ppmvd based upon a 24-hour averaging period. This averaging period as well as the means of compliance (CEMS) with CO emissions is routinely required within Florida's PSD permits.

JEA: The maximum potential VOC emissions from these units are less than the PSD significance level of 40 tons per year. The only artificial restriction on units' potential to emit is the permitted hours of operation, and compliance with this limit will be determined through operator logs. Because BACT was not triggered for VOC's and the VOC emissions are not being artificially restricted (other than through hours of operation), the Department lacks the authority to establish numeric VOC emission limits. JEA will agree to conduct a one-time stack test to verify the emission factors used, but respectfully requests that this condition be revised to clarify that these rates are not being established as not-to-exceed, enforceable emission limits. Otherwise, there could be confusion as to periodic monitoring requirements as the Title V permit is issued.

EPA: Condition 22 of the draft PSD permit limits emissions of volatile organic compounds (VOC) to 4.8 lb/hr and 8.2 lb/hr when firing natural gas and No. 2 fuel oil, respectively. Table 2-1 (maximum emission rates) of the PSD permit application states the maximum hourly VOC emission rates are 3.49 lb/hr and 7.68 lb/hr when firing natural gas and No.2 fuel oil, respectively. In order to avoid PSD review for VOC, the final PSD permit should limit the hourly emission rates to those listed in Table 2-1.

RESPONSE: Given that the application did not trigger a PSD review for VOC, the Department will allow the continuous monitoring of CO to represent the Department's means of assurance that VOC emission levels will remain below PSD thresholds after an initial demonstration (test) of VOC emissions.

EPA: Table 2-2 (PSD applicability) of the PSD permit application indicates that the potential to emit sulfur dioxide (SO2) is based on 0.2 gr/100 scf of sulfur in natural gas and 0.05 percent sulfur by weight in fuel oil. Condition 23 of the draft PSD permit limits the sulfur content of natural gas to 0.2 gr/100 scf or some other level of emissions that ensures emissions of SO2 do not exceed the PSD significant emissions threshold of 40 tons per year.

EPA: Project Definition – [As discussed above] our view is that the current PSD permit application is not for the modification of an existing major source, but addenda to the {original} PSD permit application. Therefore, the applicable PSD pollutants and air quality impact assessments should include emissions associated with the operation of the two converted combined cycle CT's and the previously permitted simple cycle CT.

RESPONSE: Given the latter of the EPA comments, the application additionally triggers a PSD review for SO_2, and the Department has incorporated this review within the final BACT Determination. On

September 24, 2001 the Department received the first of several submittals from the applicant, addressing the SO_2 Class I Increment for the project. Based upon these submittals, the applicant is able to combust oil in the combined cycle units without violating Class I increments, but under very stringent conditions. Accordingly, the final permit will provide for natural gas combustion (only) on the combined cycle units, and the issue is further addressed within the Department's Final BACT Determination.

The opacity limit is a sufficient surrogate as BACT for the particulate matter/particulate matter-10 (PM/PM_{10}) emissions. On several other occasions, DEP has established opacity limits in lieu of numeric PM/PM_{10} emission limits as BACT and EPA has not objected. The PM/PM_{10} emissions while firing natural gas and low sulfur distillate fuel oil (0.05 percent, by weight) are extremely low and unrelated to pollution control. Numeric PM/PM_{10} emission limits are unnecessary and could lead to confusion regarding periodic monitoring requirements in the future. JEA therefore respectfully requests that the PM/PM_{10} emission limits be deleted.

RESPONSE: The Department partially agrees. A numeric PM emission limit is appropriate for a unit that triggers a BACT Review, however it has on many occasions utilized opacity as a means of compliance (e.g. Brandy Branch PSD-FL-267). Accordingly, the compliance demonstration via Method 5 will be replaced with compliance demonstration to be made by opacity.

"Startup" is already appropriately defined in DEP's rules to mean "the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions." Under this definition, startup would be considered complete once the unit has operated for a period of time sufficient for the pollution control device to properly function. Startup on these CT units may not be complete until after achieving 25% of their output (or 40 MW gross, per unit). While JEA understands the Department's desire to limit operation of the units at low loads, the units may need to operate between 25 and 50% of full load to stabilize the units and ensure proper combustion characteristics and operation of the pollution control device. The existing regulatory definition of startup should be sufficient, and JEA therefore requests that the sentence defining startup as being complete once the CT achieves 25% of its output be deleted. Also, Condition 14 already provides that CT operation below 50% output is limited to 2 hours during each calendar day, unless otherwise authorized by this permit. The last sentence of this condition is redundant and can be deleted.

RESPONSE: Since the Department allows startup emissions to be excluded from the block averages in order to demonstrate compliance with the BACT-established emission standards, it is important that the Department clearly define the point at which a startup has concluded. The referenced language will be changed as follows: "A startup of any type is defined as being complete upon the first 3-hour block NO_X average of 3.5 ppmvd or less."

The time frames for conducting the initial performance tests should be fuel-specific, and DEP has previously interpreted the condition to provide for this. Because DEP has made this clarification in other permits and to be consistent with the Department's interpretation, JEA requests that the Department add the phrase "for each fuel" to this condition. Also, because facilities must sometimes seek an extension for the initial performance testing deadlines from the U.S. Environmental Protection Agency, JEA requests that a notation be added to the permit to clarify that EPA may grant such an extension and no further permitting action is needed.

RESPONSE: The Department will make related permit changes to Specific Condition 28.

RATA testing is conducted at various loads within a unit's typical operating range, which could be less than "permitted capacity" as defined in a later condition as 90 to 100 percent of the maximum heat input rate. Also, while JEA has requested that the requirement for CO CEMS be deleted, the annual CO compliance testing could be conducted during the NO_x CEM RATA tests, which would provide sufficient information to demonstrate compliance, yet not require additional stack testing at other operational loads. JEA therefore requests that this condition be revised to clarify that the annual performance test can be conducted during RATA tests.

RESPONSE: The Department will make related permit changes to Specific Condition 29.

NSPS Subpart Db is inapplicable and NSPS Subpart Dc does not establish a NO_x emissions limit. JEA previously requested that the NO_x limit for the duct burners be deleted, since the NO_x limit for the combined cycle unit is sufficient for BACT purposes. If the duct burner NO_x limit is deleted, the requirement to test duct burner emissions should be unnecessary as well. Also, JEA requests that DEP confirm that the initial Subpart GG performance testing can be conducted at full load (rather than four separate loads) and through the use of the NO_x CEMS, consistent with EPA Region 4's letter from Doug Neeley to the Region 4 Air Division Directors, dated May 26, 2000. This clarification should be made by deleting this portion of Condition 29 and revising the NO_x CEM condition.

RESPONSE: The Department will make related permit changes to Specific Conditions 29 and 30.

RATA testing is conducted at various loads within a unit's typical operating range, which could be less than "permitted capacity" as defined in condition 34 (90 to 100 percent of the maximum heat input rate). To prevent unnecessary stack testing at other operational loads, JEA requests that DEP allow the annual CO compliance testing to be conducted during the NOx CEM RATA tests, which would provide sufficient information to demonstrate compliance.

RESPONSE: The Department will allow RATA testing for the CO and NO_X CEMS to be utilized as a means of satisfying the annual testing requirements.

If EPA were to grant a waiver of the NSPS requirement to provide 30 days' prior notice of compliance testing, it would be helpful to allow DEP or RESD to make the same waiver without additional permitting activity. JEA therefore requests this clarification within Condition 35.

RESPONSE: The Department will make related permit changes to Specific Condition 35.

The diluent (CO_2 or O_2) monitoring requirements are established under the Acid Rain Program and should be deleted from the PSD permit's condition 41.

RESPONSE: The Department believes that is appropriate to specify a diluent. JEA shall be permitted to utilize O_2 as a diluent (rather than CO_2), but shall notify the Department of this change prior to CEMS installation. Specific Condition 41 will authorize this change with the appropriate notification.

The draft language of Condition 41 seems to indicate that data during startup, shutdown, and malfunction episodes must be consecutive. The excess emissions experienced during a single "startup episode" may or may not be consecutive, and the Department's rule authorizes excess emissions for 2 hours during a 24-hour period. There is no regulatory requirement that all startup data be from a consecutive period. Because data is recorded in 15-minute increments, JEA would be able to distinguish in at least 15-minute increments whether the emissions were excess or not, and whether the data should be considered an authorized excess emissions. JEA therefore requests that this language be deleted and

that the following clarifications also be made (in the next paragraph). In addition, the word "excess" appears to have been inadvertently omitted from the last sentence.
Lastly, because the acid rain CEMS are being used to demonstrate compliance with the NOx limits, the references to NSPS and the state SIP requirements should be replaced with a reference to the Acid Rain Program.

RESPONSE: For the purpose of demonstrating compliance with the emissions limitations of the permit, over the respective averaging times, for the pollutants required to demonstrate compliance by CEMS, the permit makes a provision for allowable excess emissions that are different than the rule provisions referred to by JEA. JEA will not be able to distinguish which emissions are "excess", that is, which emissions exceed emission limits, and which do not, until the averaging time has elapsed. There would not be an "excess" emission until the average emission rate measured by the CEMS is shown to have exceeded the emission limit and such averaging is not possible until the averaging time has elapsed. Because of this difficulty for the pollutants using CEMS, the permit, provides for exclusion of CEMS data that is recorded during episodes of startup, and other episodes, from the calculation of emissions over the required averaging times. JEA has the discretion, in accordance with the conditions of the permit, to determine which data it wishes to exclude from the averages for these episodes. It may be true that for certain episodes, no data need be excluded from the average for the units to be shown to be in compliance with the emission limits. The requirement that the time period of each episode be consecutive prohibits JEA from excluding data throughout the day (high recorded values, for example) that result from events that are unrelated to each other. It is not appropriate to provide a permittee with the authority to choose to exclude data simply because it is higher than the permittee would like, or to allow a permittee to claim, hours after startup has occurred for example, that high values recorded are related to that startup. Note that nothing in the permit prevents JEA from appropriately excluding data for several different episodes in one day. For example, JEA could exclude certain data related to a startup episode, and later that day exclude data related to a malfunction, and later exclude data related to another malfunction or a shutdown episode. JEA could also startup and shutdown the unit several times in a given day, provided that data excluded for each episode be consecutive for that episode. The only restraint on this is that the permit limits the total amount of time that data may be excluded in any given day for all such episodes.

The Department cannot omit reference to NSPS and SIP requirements because the emissions units are subject to these requirements in addition to the acid rain requirements. The same CEMS system may be used to demonstrate compliance with the emission limits established by these different regulatory programs, but that does not somehow exempt the units from the applicability of these requirements.

JEA requests a permitting note stating that EPA has already approved a custom fuel monitoring plan schedule, and that an additional application or request is not necessary.

RESPONSE: The Department will make related permit changes to Specific Condition 42.

CONCLUSION

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

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

JEA
21 West Church Street
Jacksonville, FL 32234

File No.	PSD-FL-310 (PA00-43)
FID No.	0310485
SIC No.	4911
Expires:	December 31, 2005

Authorized Representative:

Mr. Walter P. Bussells, Managing Director and CEO

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of a nominal 540 megawatt (MW) Combined Cycle generating unit consisting of: two nominal 170 MW, stationary (existing) combustion turbine-electrical generators fired on natural gas (and oil capability) equipped with evaporative coolers; two (new) supplementally-fired heat recovery steam generators (HRSGs) and associated 190-foot stacks; one (new) nominal 200 MW steam electrical generator; one (new) freshwater cooling tower; two (new) selective catalytic reduction units including ancillary equipment and ammonia storage. The combined generating units will achieve approximately 570 megawatts in combined cycle operation during extreme winter peaking conditions. The facility is designated as Brandy Branch Generating Facility and is situated 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.

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).

The attached Appendix is made a part of this permit:

Appendix GC Construction Permit General Conditions

Ctt Javey 3/28/02

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

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

The proposed conversion of two existing combustion turbines at the Brandy Branch Generating Facility will result in a (nominal) 540 MW combined cycle plant. The units were originally authorized as simple cycle units under PSD Permit No. PSD-FL-267. The current project includes: the two nominal 170 MW GE 7FA combustion turbine-electrical generators re-configured for combined cycle, operating solely on pipeline quality natural gas and equipped with evaporative coolers; two supplementally-fired heat recovery steam generators (HRSG); one 200 MW (nominal output) steam turbine; one fresh water cooling tower and ancillary equipment. Emissions from the Brandy Branch combined cycle unit will be controlled by Dry Low NO_X (DLN) combustors and selective catalytic reduction (SCR). Clean fuels and good combustion practices will be employed to control all pollutants. Upon conversion of Units 002 and 003 to combined cycle units, PSD Permit No. PSD-FL-267 shall no longer be in effect for Units 002 and 003 since it has been superseded by this PSD Permit (PSD-FL-310). PSD Permit No. PSD-FL-267 will continue to be in effect for Unit 001 and the fuel oil storage tanks. Units 002 and 003 may continue to operate under PSD-FL-267 and in simple cycle mode until the conversion to combined cycle mode is complete.

EMISSIONS UNITS

This permit addresses the following emissions units:

EMISSIONS UNIT	SYSTEM	Emission Unit Description
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
003	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine- Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
007	Water Cooling	One Mechanical Draft Cooling Tower

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 within an industry (fossil fuel-fired steam electric plant) included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of NO_X, 25/15 TPY of

PM/PM_{10} and 100 TPY of CO. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This project has been submitted as if it is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting. [Chapter 403.503 (12), F.S., Definitions]

This facility is also subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

PERMIT SCHEDULE

- 03/27/02 PSD Permit Issued
- 03/26/02 Site Certification Issued
- 05/18/01 Notice of Intent to Issue PSD Permit published in The Florida Times-Union
- 04/26/01 Distributed Intent to Issue Permit
- 12/08/00 Received PSD Application

RELEVANT DOCUMENTS:

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

- Department's Final Determination and Best Available Control Technology Determination issued for original project (PSD-FL-267) including PSD permit revisions.
- Application received on December 8, 2000.
- Responses to Sufficiency Items received on March 29, 2001.
- E-mail received from Fish & Wildlife Service dated April 4, 2001.
- Department's Intent to Issue and Public Notice Package dated April 26, 2001.
- Department's Draft Permit and Draft BACT determination dated April 26, 2001.
- Letter from EPA Region IV dated July 19, 2001.
- Additional SO_2 Class I Increment Analysis and related modeling by Black & Veatch received September 24, 2001 and November 21, 2001.
- Site Certification for the Brandy Branch Generating Facility dated March 26, 2002.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

GENERAL AND 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 904/807-3300; 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, F.A.C.]

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) and 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, short-term or annual emission limits, annual fuel heat input limits, changes in methods of operation or similar changes. [40 CFR 52.21(j), 40 CFR 51.166(j) and Rule 62-4.070 F.A.C.]

8. Permit Extension: The permittee, for good cause, may request that this PSD 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. In conjunction with extension of the 18-month periods to commence or continue construction, or extension of the December 31, 2005 permit expiration date, the permittee may be

required to demonstrate the adequacy of any previous determination of best available control technology for the source, at the Department's discretion. [Rule 62-4.080, F.A.C.]

9. Application for Title IV Permit: A revised application for a Title IV Acid Rain Permit must be submitted to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]
10. Application for Title V Permit: An application for a Title V operating permit revision, 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.]
11. 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.]
12. 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.]
13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
14. 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.

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, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 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 Emissions Units 002 and 003. Direct Power Generation, each consisting of a nominal 170-megawatt combustion turbine-electrical generator, 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). Additionally, each Emissions Unit consists of a supplementally-fired heat recovery steam generator equipped with a natural gas fired 85 MMBTU/hr duct burner (HHV) and combined with one 200 MW steam electrical generator. The duct burners shall comply with all applicable provisions of 40CFR60, Subpart Dc, Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units, adopted by reference in Rule 62-204.800(7), F.A.C.

5. ARMS Emission Unit 007. Cooling Tower, an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because chromium-based chemical treatment is not used.

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 fuel oil containing sulfur content of 0.05% or less shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); see BACT Determination for detailed information]

8. Combustion Turbine Capacity: The maximum heat input rates, based on the higher heating value (HHV) of the fuel to this Unit shall not exceed 1,911 million Btu per hour (MMBtu/hr) when firing natural gas nor 2060 MMBtu/hr for oil firing. This maximum heat input rate will vary depending upon turbine inlet 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 emission 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.} [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Heat Recovery Steam Generators equipped with Duct Burners: The maximum heat input rate of each natural gas fired duct burner shall not exceed 85 MMBtu/hr (HHV). {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 emission 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.} [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. 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.

11. 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 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.]

12. 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.]

13. 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.]

14. Maximum allowable hours of operation for the 540 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. The combined hours of fuel oil firing for the two combined cycle combustion turbines is limited to 576 hours per consecutive 12-month period and fuel oil firing for the simple cycle unit is limited to 750 hours per consecutive 12-month period. In the event that any of the 3 emission units (simple or combined cycle) fires fuel oil during a calendar day, that unit shall be limited to 16 hours of daily operation on any fuel. Additionally, the other 2 units shall not be fired on any fuel for the calendar day. Unless otherwise authorized by this permit, CT operation below 50% output shall be limited to 2 hours during each calendar day. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

15. Neither EU-002 nor EU-003 may be operated without the use of the SCR system except during periods of startup and shutdown in accordance with the manufacturers requirements.

CONTROL TECHNOLOGY

16. Dry Low NO_X (DLN) combustors shall be installed on each stationary combustion turbine and the permittee shall install a selective catalytic reduction system to comply with the NO_X and ammonia limits listed in Specific Condition 20. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

17. Wet injection shall additionally be installed on each stationary combustion turbine for use during fuel oil firing, in conjunction with the SCR referenced in Specific Condition 16. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

18. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 20 through 24. [Rule 62-4.070, Rule 62-204.800, F.A.C.]

19. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions. A certification following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002-gallons/100 gallons recirculation water flowrate.

EMISSION LIMITS AND STANDARDS

20. Nitrogen Oxides (NO_X) Emissions:
    - The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on natural gas and the duct burner on, shall not exceed 3.5 ppmvd @15% O_2 on a 3-hr block average. The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on fuel oil (duct burner firing not permitted), shall not exceed 15.0 ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
    - The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 5.0 ppmvd @15% O_2 while firing natural gas, nor 9 ppmvd @ 15%O_2 while firing oil. The compliance procedures are described in Specific Conditions 29 and 45. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]
21. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on any fuel (with duct burners on or off) shall not exceed 14 ppmvd @15% O_2, on a 24-hr block average to be demonstrated by CEMS. [BACT, Rule 62-212.400, F.A.C.]
22. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall not exceed 3.49 lb/hour and with the combustion turbine operating on oil shall not exceed 7.68 lb/hr, to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. Thereafter, continuous monitoring of CO shall represent a surrogate for VOC emissions and provide assurance that a BACT Determination is not required. [PSD Avoidance, Rule 62-212.400, F.A.C.]
23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 2 grains per 100 standard cubic foot) and a limited amount of 0.05% sulfur oil. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 40 and 42 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the combustion turbines as well as the duct burners. [BACT, 40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.].
24. PM/PM_{10} and Visible emissions (VE): VE emissions shall not exceed 10 percent opacity from the stack in use. PM/PM_{10} emissions from each combustion turbine and HRSG train shall not exceed 20.6 lb/hr at 100% output firing natural gas with the duct burner on and 62.1 lb/hr at 100% output firing fuel oil to be demonstrated by opacity. [BACT, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. 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 except during "warm" or "cold" start-up to combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed in any 24-hour period. During warm startup from combined cycle operation, up to three hours of excess emissions are allowed in any 24-hour period. Cold start-up is defined as a startup to combined cycle operation following a shutdown lasting at least 72 hours. Warm startup is defined as a startup to combined cycle operation following a shutdown lasting at least 24 hours. A startup of any type is defined as being complete upon the first 3-

hour block NO_X average of 3.5 ppmvd or less (15 ppmvd or less for oil firing). Operation below 50% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [Rule 62-210.700, F.A.C.].

26. 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. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

27. Excess Emissions Report: If excess emissions occur for more than two hours 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, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions 41 through 45, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 20 through 24. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

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, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C. (unless the U.S. Environmental Protection Agency authorizes an extension).

29. Initial (I) performance tests shall be performed by the deadlines in Specific Condition 28. Initial tests shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or change of combustors, if specifically requested by the DEP or RESD on a case-by-case basis. 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 these units 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. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.

    - 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). This testing may be conducted during the NO_X RATA tests, which includes loads that are less than permitted capacity.
    - EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
    - Method CTM-027 for ammonia slip during oil firing (I) and natural gas firing (I, A).

The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O_2) at the measured lb/hr NO_X emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition 45.

30. Continuous compliance with the CO and NO_X emission limits: Continuous compliance with the CO and NO_X emission limits shall be demonstrated by the CEM system on the specified hour average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Specific Condition 41 further describes the CEM system requirements. Excess emissions periods shall be reported as required in Condition 27. Since CEMS are used for compliance, testing at four separate loads is not required for demonstrating initial compliance under 40 CFR 60.335(c)(3), consistent with recent EPA guidance. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

31. Compliance with the SO_2 and PM/PM_{10} emission limits: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) 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. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. 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) (1998 version).

32. Compliance with CO emission limit: Annual RATA testing for the CO and NO_X CEMS shall be required pursuant to 40 CFR 75.

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

34. Testing procedures: Unless otherwise specified, 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). Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, 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 tests (unless waived by the affected agency).

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. Compliance Test Reports: 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:

    (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 be kept for each consecutive 12-month period by fuel type.

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

    (4) Daily hours of operation when the CT is being fired and the SCR is not in service, along with support documentation demonstrating that the unit was in a startup or shutdown condition.

    (5) Daily (as-fired) sulfur content of fuel oil 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 emissions of NO_X and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NO_X and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_X and CO established in this permit. Compliance with the emission limits for NOx shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack

test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

The NO_X monitor shall be certified and operated in accordance with the following requirements. The NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 3 or 24-hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to RESD and the Department's Northeast District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 20 ppm, and the span for the upper range shall not be greater than 100 ppm, as corrected to 15% O_2. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

NO_X, CO and CO_2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit. Periods of data excluded for startup shall not exceed two hours in any block 24-hour period except for "warm" or "cold" startup. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period. Periods of data excluded for warm startup shall not exceed three hours in any 24-hour block period. Periods of data excluded for hot startups, shutdowns or malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all combined startup, shutdown and malfunction episodes shall not exceed four hours in any 24-hour block period. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.

Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

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

Upon request from the Department or RESD, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. [Rules 62-4.070(3) and 62-212.400., F.A.C., and BACT]

JEA shall be permitted to utilize O_2 as a diluent (rather than CO_2), but shall notify the Department of this change prior to CEMS installation.

[Note: Compliance with these requirements will ensure compliance with the other CEM system requirements of this permit to comply with Subpart GG requirements, as well as the applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.7(a)(5) and 40 CFR 60.13, and with 40 CFR Part 51, Appendix P, 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60, Appendix F, Quality Assurance Procedures].

42. Fuel Monitoring Schedule: An optional SO_2 Emissions Data Protocol (without additional EPA approvals) for Gas-Fired and Oil-Fired Units pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

   - The permittee shall apply for an Acid Rain permit within 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 the sole use of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)) for the CT's.
   - Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
   - 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 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).

43. 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. No later than 90 days prior to operation, the permittee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition.

- 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]

44. Subpart Dc Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Dc].

45. Selective Catalytic Reduction System (SCR) Compliance Procedures:

- An annual stack emission test for nitrogen oxides and ammonia from the CT/HRSG pair shall be simultaneously conducted while firing natural gas and operating with the duct burner on as defined in Specific Condition 20. The ammonia injection rate necessary to comply with the NO_X standard shall be established and reported during each annual performance test.

- The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by manufacturer's guidelines and in accordance with this permit.

- The permittee shall install and operate an ammonia flow meter to continuously measure and record the ammonia injection rate to the SCR system of the CT/HRSG set. It shall be maintained and calibrated according to the manufacturer's specifications.

- During the stack test, the permittee (at each tested load condition) shall determine and report the ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at the ammonia flow rate, which was established during the last stack test.

- Ammonia emissions shall be calculated continuously using inlet and outlet NO_X concentrations from the SCR system and ammonia flow supplied to the SCR system. The calculation procedure shall be provided with the CEM monitoring plan required by 40CFR Part 75. The following calculation represents one means by which the permittee may demonstrate compliance with this condition:

  Ammonia slip @ 15%O_2 = (A-(BxC/1,000,000)) x (1,000,000/B) x D, where:
  A= ammonia injection rate (lb/hr)/ 17 (lb/lb.mol)
  B = dry gas exhaust flow rate (lb/hr) / 29 (lb/lb.mol)
  C = change in measured NO_X (ppmv@15%O_2) across catalyst
  D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

  The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device utilized to make the ammonia emission measurement and submitted with each annual compliance test.

- Upon specific request by RESD or the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements, in order to demonstrate that all NO_X and ammonia slip related permit limits can be complied with.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

JEA Brandy Branch Facility
PSD-FL-310 and 0310485-003-AC
Duval County, Florida

BACKGROUND

The applicant, JEA (formerly Jacksonville Electric Authority) proposes to convert (to combined cycle) two of the three newly installed nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators (CT's) at the Brandy Branch Facility near Baldwin City, Duval County. Past emissions are considered negligible as the subject CT's have had minimal operating time. 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), sulfur dioxide (SO_2) and nitrogen oxides (NO_X). 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 project consists of the addition of two supplementary-fired HRSGs, a steam turbine and a cooling tower. JEA proposes to operate each CT/HRSG pair up to 8760 hours per year firing pipeline natural gas, with up to 288 hours of that time firing a 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 April 26, 2001, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on December 8, 2000 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch. Responses to Department questions were received on March 29, 2001 and September 24, 2001 and comprise a part of this review. Atmospheric modeling runs conducted through November 2001 additionally are incorporated within this Determination.

REVIEW GROUP MEMBER:

Michael P. Halpin, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	SCR + DLN Combustors (Gas) SCR + Water Injection (Oil)	3.5 ppmvd @ 15% O_2 (gas) 15 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (288 hr/yr) Combustion Controls	10% Opacity
Carbon Monoxide	As Above	12.21 ppmvd (gas, baseload) 14.17 ppmvd (oil baseload)
PM – Cooling Tower	Drift Eliminators	.002 gal/100 gal recirculation flow (equivalent to 0.08 lb/hr PM)

According to the application, the maximum emissions from this project will be approximately 233 tons per year (TPY) of NO_X, 465 TPY of CO and 186 TPY of PM/PM_{10}. The applicant indicates that annual emissions of other pollutants are less than the PSD significance thresholds. These values are listed in the Technical Evaluation and Preliminary Determination issued on April 26, 2001.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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 units such as those planned for the Brandy Branch combined cycle conversion.

The duct burners required for supplementary gas firing of the HRSG are subject to 40 CFR 60, Subpart Dc, Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units.

No National Emission Standards for Hazardous Air Pollutants exist for gas-fired duct burners. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines and based upon applicant submittals this project does not require a MACT Determination.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent BACT determinations by states for combined cycle stationary gas turbine projects. These are projects incorporating large prime movers capable of producing more than 150 MW excluding the steam cycle. Such units are typically categorized as F Class Frame units. The applicant's proposed BACT is included for reference.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

TABLE 1

RECENT BACT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	Power Output Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Mobile Energy, AL	~250	~3.5 - NG (CT&DB) ~11 – FO (CT&DB)	DLN & SCR	178 MW GE 7FA CT 1/99 585 MMBtu Duct Burner
KUA Cane Island 3	250	3.5 - (CT&DB)	DLN/SCR	170 MW GE 7FA. 11/99 Ammonia slip = 5 ppmvd
Calpine Osprey	545	3.5 – (CT& DB& PA)	DLN/SCR	Ammonia slip = 9 ppmvd (3 hr avg.)
FPC Hines (PB2)	530	3.5 – NG 12 – FO	DLN/CSR	Ammonia slip = 5 ppmvd gas; Ammonia slip = 9 ppmvd oil
Calpine Bullhead City	545	3.0 – (CT&DB)	DLN/SCR	Replace SCR catalyst after 36 mo.
Calpine Blue Heron	545	3.5 – (CT& DB)	DLN/SCR	Ammonia slip = 5 ppmvd
JEA Brandy Branch (proposed)	570	3.5 – (CT& DB) 15 - FO	DLN/SCR	Ammonia slip ~ 10 ppm

DB = Duct Burner
NG = Natural Gas
FO = Fuel Oil
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection
CT = Comb.Turbine
DB = Duct Burner
PA = Pwr. Augmentation
PA = Power Augmentation
WH = Westinghouse
GE = General Electric

TABLE 2

RECENT BACT LIMITS FOR CARBON MONOXIDE, PARTICULATE MATTER, AND VISIBILITY FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/MMBtu)	PM - lb/MMBtu (or gr/dscf or lb/hr)	Technology and Comments
Mobile Energy, AL	~18 – NG (CT&DB) ~26 – FO (CT&DB)	10% Opacity	Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	10% Opacity	Clean Fuels Good Combustion
Calpine Osprey	10 – NG (CT only) 17 – NG (off-normal)	10% Opacity 24.1 lb/hr (CT & DB)	Clean Fuels Good Combustion
FPC Hines (PB2)	16 – NG 30 – FO	7.3 lb/hr NG 64.8 lb/hr (Fuel Oil)	Clean Fuels Good Combustion
Calpine Bullhead City	10 – NG (CT & DB) 33.9 – NG (DB & PA) 3 hour rolling average	18.3 lb/hr (CT) 22.8 lb/hr (DB & PA)	Clean Fuels Good Combustion
Calpine Blue Heron	10 – NG (CT only) 17 – NG (off-normal)	10% Opacity 26.0 lb/hr (CT & DB)	Clean Fuels Good Combustion
JEA Brandy Branch (proposed)	12.21 – NG (CT & DB) 14.17 – FO	10% Opacity 20.6 lb/hr (CT & DB) 62.1 lb/hr (Fuel Oil)	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, key information reviewed by the Department includes:

- Master Overview for Alabama Power Plant Barry Project received in 1998
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island 3
- Presentations by Black & Veatch and General Electric at EPA Region IV on March 4, 1999
- Texas Natural Resource Conservation Commission Draft Tier I BACT for August, 1999
- Texas Natural Resource Conservation Commission Website – www.tnrcc.state.tx.us
- 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 Kennedy and Brandy Branch Plant CT's
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochures on Duct Burners
- Test data from Tallahassee Purdom No. 8

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. 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 up to 200 ppmvd @15% O_2 for the JEA turbines. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NO_X emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NO_X control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NO_X emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NO_X emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NO_X emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

Combustion Controls

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% to 100% of base load and provides the lowest NO_X emissions. Due to the intricate air and fuel staging necessary for dry low-NO_X combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%.

Figure A (below) is an example of an in-line duct burner arrangement. Since duct burners operate at lower temperature and pressure than the combustion turbine, the potential for emissions is generally lower. Furthermore the duct burner size for this project is only 170 MMBtu/hr compared with the turbine that can accommodate a heat input greater than 1700 MMBtu/hr (LHV). The duct burners will be of a Low NO_X design and will be used to compensate for loss of capacity at high ambient temperatures.

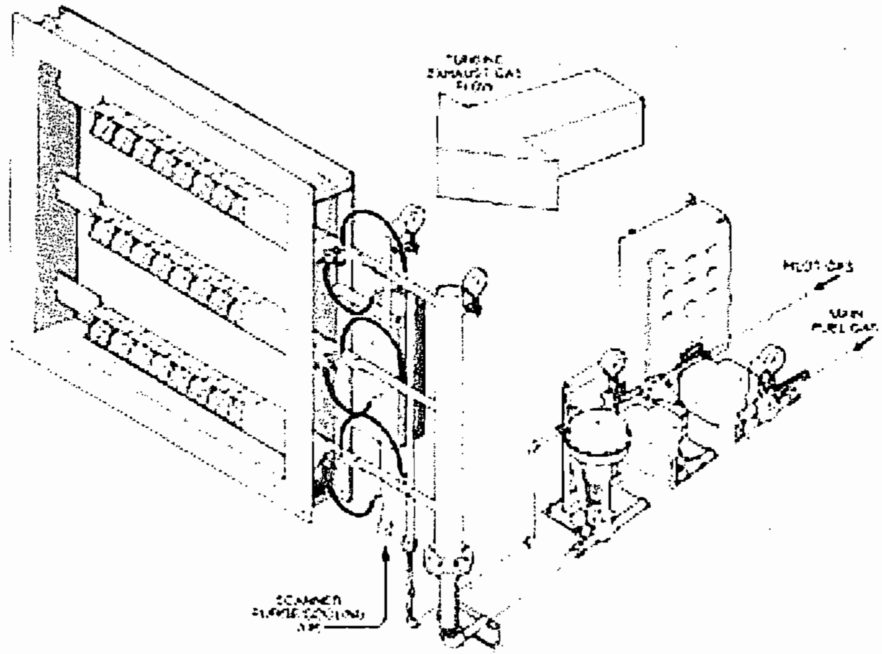


FIGURE A

Selective Catalytic Reduction

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 commonplace and have recently been specified for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review concluded that the unit would be capable of combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10ppmvd of NO_X. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, as indicated by Mitsubishi who reports that SCR's are installed on 40 utility boilers which combust *residual* oil. 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.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) currently 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. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3. New combined cycle combustion turbine projects in Florida are normally considered to be prime candidates for SCR, and this is the technology of choice for the Brandy Branch facility, at an estimated cost effectiveness of $4200 per ton (well within current standards).

Figure B is a photograph of FPC Hines Energy Complex. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. Figure C below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met.

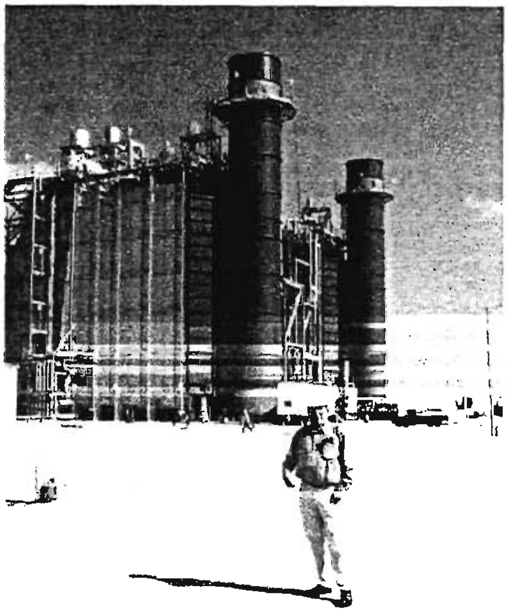


Figure B

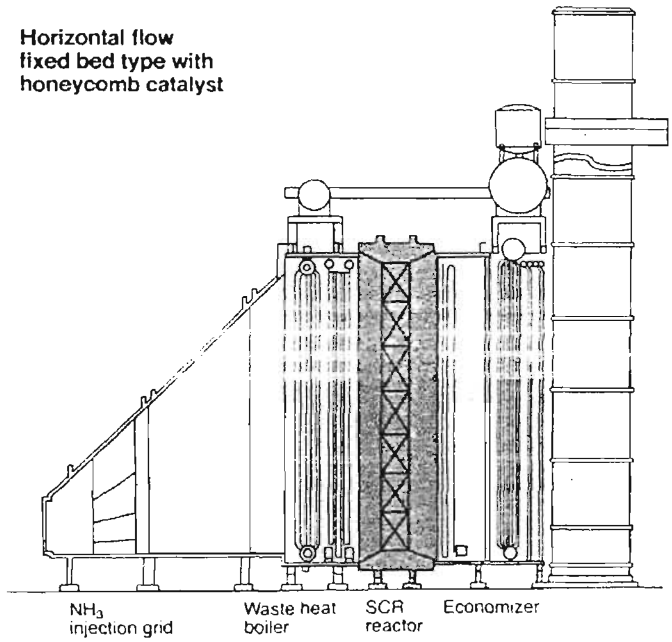


Figure C

Excessive ammonia use tends to increase emissions of ammonia (slip), and particulate matter (when sulfur-bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits at 3.5 ppmvd NO_X (which is proposed for Brandy Branch) are being routinely specified using SCR for F Class projects (with large in-line duct burners) in the Southeast and even lower limits in the southwest.

Selective Non-Catalytic Reduction

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 SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market an SNCR for NO_X control within the temperature ranges for which this project will operate (700 – 1400°F). The process also requires a low oxygen content in the exhaust stream in order to be effective. Given that a top-down review leads to an SCR in this application, SNCR does not merit further consideration.

Emerging Technologies: SCONOx™ and XONON™

SCONOx™ 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 dilute hydrogen 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 permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx ™[2]. The overall project includes several more 250 MW blocks with SCR for control.[3] According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E Generating has been approved to install SCONOx™ on two F frame units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, 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.

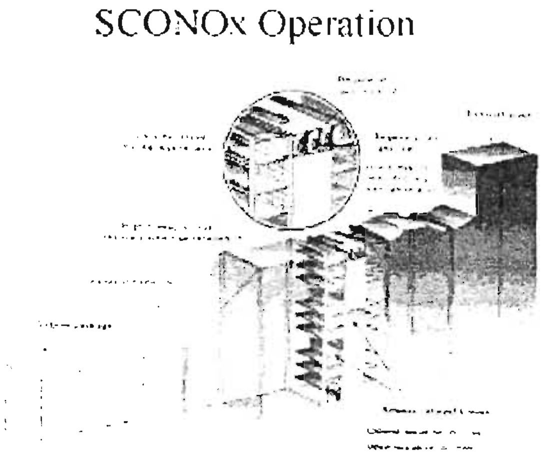


Figure D

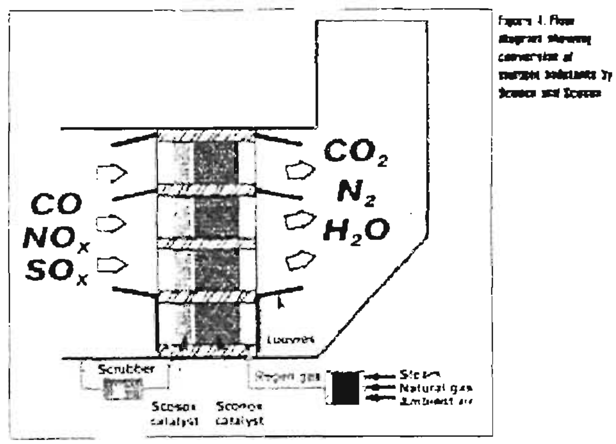


Figure E

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 VOC and CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently only due to cost considerations. The Department is interested in seeing this technology implemented in Florida and intends to continue to work with applicants seeking an opportunity to demonstrate ammonia-free emissions on a large unit. The Department estimates that the application of this control technology to the Brandy Branch Facility results in cost-effectiveness of just less than $10,000 per ton of NO_X removed. Although there are specific items within the applicant's analysis (which estimates a cost effectiveness of $62,000 per ton) that the Department cannot support (e.g. replacement power costs, lost revenues, etc.) on balance the Department concurs with the conclusion that $SCONO_X$ is not likely cost-effective for this project.

Catalytica Energy Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. 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 SCONOx™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

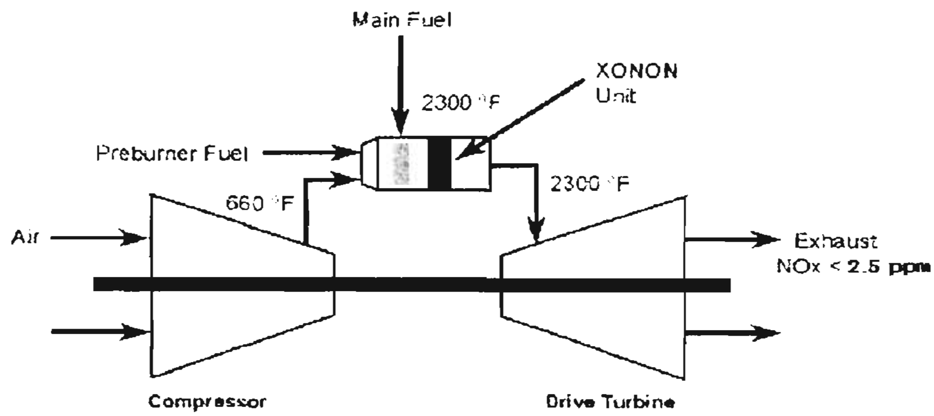
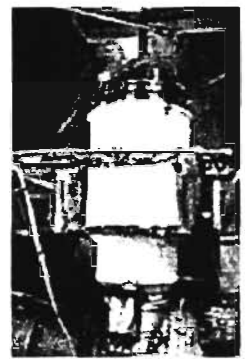


Figure F



XONON-2 installed with test instruments

Figure G

On February 8, 2001, Catalytica Energy Systems, Inc. announced that its XONON™ Cool Combustion system had successfully completed an evaluation process by the U.S. Environmental Protection Agency (EPA), which verified the ultra-low emissions performance of a XONON™-equipped gas turbine operating at Silicon Valley Power. The performance results gathered through the EPA's Environmental Technology Verification (ETV) Program provide high-quality, third party confirmation of XONON™ 's ability to deliver a near-zero emissions solution for gas turbine power production. The verification, which was conducted over a two-day period on a XONON™-equipped Kawasaki M1A-13A (1.4 MW) gas turbine operating at Silicon Valley Power, recorded nitrogen oxides (NO_X) emissions of less than 2.5 parts per million (ppm) and ultra-low emissions of carbon monoxide and unburned hydrocarbons.

The XONON™-equipped Kawasaki M1A-13A gas turbine has operated for over 7400 hours at Silicon Valley Power (SVP), a municipally owned utility, supplying near pollution-free power to the residents of the City of Santa Clara, California, with NO_X levels averaging under 2.5 ppm. Three XONON™-equipped Kawasaki M1A-13X turbines, a slightly modified commercial version of the M1A-13A, are expected to enter commercial service in late 2001 in Massachusetts at a healthcare facility of a U.S. Government agency.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to the commercialization of the XONON™ system for new and existing GE gas turbines. The agreement provides for the collaborative adaptation of XONON™ combustion technology to GE gas turbines for commercial sale. In December 1999, GE accepted the first order for XONON™ -equipped GE 7FA gas turbines as the preferred emission control system for Enron's proposed Pastoria Energy Facility. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. However, the technology cannot (at this time) be recommended for the attendant project.

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 is an inherently clean fuel and contains no ash. Natural gas will be the main fuel fired at the Brandy Branch facility, with a (proposed) small amount (288 hours per year) of 0.05% Sulfur fuel oil. Both of these fuels are efficiently combusted in gas turbines making any conceivable add-on control technique for PM/PM_{10} unnecessary. 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.

The applicant has identified PM emissions of less than 1 TPY from the cooling tower. Accordingly, drift eliminators shall be installed which shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate. No PM testing is required because the Department's Emission Monitoring Section has determined that there currently is no appropriate PM test method for this type of cooling tower.

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.

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Calpine Sutter in California. The permitted CO values of these units are between 3 and 5 ppmvd. 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 will install oxidation catalyst 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. These installations typically achieve emissions between 9 and 25 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. JEA proposes to meet a limit of 12.21 ppmvd while firing natural gas with the duct burner on. Additionally, the applicant proposes a higher value of 14.17 ppmvd while firing fuel oil.

Test data provided to the Department provides reasonable assurance that the GE 7FA units selected by JEA will achieve values well below those proposed, without requiring installation of an oxidation catalyst, although the estimated cost effectiveness of $2700 per ton is an acceptable cost. The Department will require the use of a CEMS for compliance on a 24-hour block average. Due to the reasonableness of the applicant's proposal, the Department will establish one limit for CO compliance set at 14 ppmvd for all operating modes (gas and oil), and will not impose a further limit on hours of operation as is often done for hours of duct burner firing. However, operating time below 50% output will be restricted as neither emission guarantees nor modeling can support the required emission levels at lower outputs.

REVIEW OF SULFUR DIOXIDE (SO_2) CONTROL TECHNOLOGIES

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 a limited amount of 0.05% or less sulfur oil and pipeline natural gas. The Department will set the BACT standard at 2 grains of sulfur per 100 standard cubic feet (gr. S/100ft^3) although it expects the emissions to be lower, as the typical natural gas in Florida contains less than 1 grain of sulfur per 100 standard cubic feet (gr. S/100ft^3). Although this value is well below the "default" maximum value of 20 gr. S/100 ft^3, modeling of the potential impacts to nearby Class I areas has revealed that 2 gr. S/100 ft^3 may be too high, should these emission units also be authorized to concurrently combust oil. Accordingly, this BACT Determination will outline the more stringent requirements, under which the combined cycle units may be allowed to combust oil.

The combined hours of fuel oil firing for the two combined cycle combustion turbines will be limited to 576 hours per consecutive 12-month period and fuel oil firing for the simple cycle unit will continue to be limited to 750 hours per consecutive 12-month period. In the event that any of the 3 emission units (simple or combined cycle) fire fuel oil during a calendar day, that unit shall be limited to 16 hours of daily operation on any fuel. Additionally, the other 2 units shall not be fired on any fuel for the calendar day.

One additional scenario may be authorized by permit, but should JEA wish to deviate from these very prescriptive requirements, BACT and modeling will need to be revisited. This scenario allows gas firing to occur on any of the 3 emission units in conjunction with the aforementioned allowances for oil firing. However, the following additional requirements (Table 3) are associated with this scenario, and SO_2 CEMS are required to be installed on each emissions unit.

TABLE 3

Emission Unit	Daily Operation of CC unit on oil		Daily Operation of SC unit on oil	
	3 Hr Average SO_2 Limit	24 Hr Average SO_2 Limit	3 Hr Average SO_2 Limit	24 Hr Average SO_2 Limit
Simple Cycle	1.1 lb/hr	1.1 lb/hr	98.2 lb/hr	65.8 lb/hr
One CC Unit	109.4 lb/hr	73.3 lb/hr	1.2 lb/hr	1.2 lb/hr
Other CC Unit	1.2 lb/hr	1.2 lb/hr	1.2 lb/hr	1.2 lb/hr

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the JEA project assuming full load. Values for NO_X and CO are corrected to 15% O_2. The emission limits as well as the applicable averaging times are given in the permit Specific Conditions No. 20 through 24. Annual emissions of VOC should not exceed the PSD Significance levels based upon JEA's proposed emission rates. Accordingly, JEA's proposed emission rates shall become binding limits and placed within the permit in order to ensure that BACT does not apply.

POLLUTANT	CONTROL TECHNOLOGY	BACT DETERMINATION
PM/PM_{10}, VE	Pipeline Natural Gas - 0.05% Sulfur Oil Good Combustion - Inlet Air Filtering	10 Percent Opacity; Note: Will yield approximately 20.6 lb/hr during DB; 62.1 lb/hr during oil firing
CO (all operating modes)	Pipeline Natural Gas - 0.05% Sulfur Oil Good Combustion	14 ppmvd – 24 hour block average
NO_X (all operating modes)	DLN & SCR	3.5 ppmvd (SCR) – 3 hour block average (gas, CT/DB) DB limited to 0.1 lb/MMBtu 15 ppmvd (SCR) – 3 hour block average (oil, no DB) Ammonia slip = 5 ppmvd (gas); 9 ppmvd (oil)
PM (cooling tower)	High efficiency drift eliminators	0.002% drift loss
SO_2	Pipeline Natural Gas - 0.05% Sulfur Oil	2 grains of sulfur per 100 ft^3 gas; 0.05% Sulfur Oil; alternate limits as identified in Table 3 above
VOC	Pipeline Natural Gas - 0.05% Sulfur Oil Good Combustion	Not Determined by BACT (used for PSD avoidance): 3.49 lb/hr / 7.68 lb/hr (gas and oil respectively)

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd. It has been achieved at a small combustion turbine installation using $SCONO_X$.
- EPA Region IV advised that the Department (in a draft BACT) did not present "any unusual site-specific conditions associated with the KUA Cane Island 3 project to indicate that the use of SCR to achieve 3.5 ppmvd would create greater problems than experienced elsewhere at other similar facilities."[5] The Fish & Wildlife Service had similar comments for Calpine Osprey Energy Center.[9]
- EPA advised FDEP that it intended to appeal the KUA Permit if the Department did not require a NO_X emissions rate of 3.5 ppmvd when firing natural gas.[6]
- FDEP considers a 3-hour averaging time for NO_X compliance and a 5-ppmvd ammonia slip rate to be BACT, as recently determined by CPV Gulf Coast (PSD-FL-300) and Calpine Blue Heron (PSD-FL-309) and other recent combined cycle projects.
- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5 ppmvd).[7]
- For reference, CO limits for the Calpine Blue Heron and FPC Hines projects are 17 ppmvd and 16 ppmvd respectively for all operating modes. Annualized levels above 16 ppmvd on throughputs of "F" machines tend to yield acceptable cost effectiveness values for CO reduction via oxidation catalyst.
- The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT.
- BACT for SO_2 has been established based upon multiple modeling scenarios, and after consultation with EPA Region IV.

POLLUTANT	COMPLIANCE PROCEDURE
PM/Visible Emissions	Method 5 (initial test only) and Method 9 (annually)
Carbon Monoxide	CEMS plus Annual Method 10 during operation at capacity with use of duct burners. Initial Method 10 Test only for oil firing
NO_X 3-hr block average	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 or 7E
SO_2	Fuel sampling or CEMS as described above
Ammonia Slip	CTM-027 initial and annual (The test and analyses shall be conducted so that the minimum detection limit is 1 ppmvd)
VOC	EPA Method 18, 25 or 25A (initial test only); compliance thereafter by CO CEMS

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable standard. These excess emissions periods shall be reported as required in Specific Condition 27 of the Permit. A valid hourly emission rate shall be calculated for each hour in which at least two pollutant concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C. and 62-210.700 F.A.C.].

The following emission levels represent excess emission *estimates* during startup and shutdown periods:

STARTUP TYPE	TIME REQUIRED	ESTIMATED EMISSION MAXIMUM LEVELS BY POLLUTANT FOR EACH CT (TOTAL lbm)		
		NO_X	CO	PM
Hot	60 minutes	104	652	18
Warm	129 minutes	283	1360	38
Cold	228 minutes	768	2365	68

The following emissions (TPY) are shown for informational purposes only. They represent a *conservative* estimate of annualized startup emissions, which are largely controllable through best operating practices. Since each startup requires many hours of preceding shutdown time where emissions are zero, there will likely be *no annual net emission increase* from the previously estimated TPY:

STARTUP TYPE	NO. REQUIRED	NO_X	CO	PM
Hot	100	10.4	65.2	1.8
Warm	50	14.2	68	1.9
Cold	10	7.7	23.7	0.7
Total	310	32.2	156.9	4.4

Excess emissions may occur under the following startup scenarios, subject to Rule 62-210.700, F.A.C.:

Hot Start: One hour following a HRSG shutdown less than or equal to 24 hours.

Warm Start: Three hours following a HRSG shutdown greater than 24 hours.

Cold Start: Four hours following a HRSG shutdown greater than or equal to 72 hours.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer MPH
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

CH Fancy

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

3/28/02

Date:

Approved By:

CH Fancy

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

3/28/02

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. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[5] Letter. Neeley, R. Douglas, EPA Region IV, to Fancy, C.H., FDEP. Draft PSD Permit – KUA Project. February 2, 1999.

[6] Letter. Smith, Winston, EPA Region IV, to Rhodes, H.L., FDEP. Proposed KUA Permit. November 8, 1999.

[7] Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.

[9.] Letter. Porter, Ellen to Linero, A.A., FDEP. Technical Review of Prevention of Significant Deterioration Permit Application For Osprey Energy Center. April 17, 2000.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

Memorandum

Florida Department of Environmental Protection

TO: Howard L. Rhodes

THRU: Clair Fancy
Al Linero

FROM: Michael P. Halpin MH

DATE: March 26, 2002

SUBJECT: JEA Brandy Branch Combined Cycle Conversion

I signed Howard out 3/28/02

Attached for approval and signature is a PSD permit for the subject (existing) facility. The 540 megawatt combined cycle electrical power generating unit will consist of: two nominal 170 MW "F" class combustion turbine-electrical generators; two supplementally fired heat recovery steam generators; one 200 MW steam-electrical generator; one mechanical draft cooling tower; a fuel oil storage tank and ancillary equipment. This project was subject to the Power Plant Siting Act.

The permit allows for NO_X emissions of 3.5 ppmvd on a 3-hour block average (via SCR) with ammonia slip limited to 5 ppm. Additionally, the permit will require a CEMS for the continuous measurement of CO emissions, which will be based upon a 24-hour block average.

Emissions of sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently clean fuels used.

The Siting Board met on March 12, 2002 and approved the Recommended Order of Judge Johnston. Accordingly, I recommend your approval and signature.

Attachments

/mph

N. Bert Gianazza, P.E.
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202

Charles J. Schutty, P.E.
Black & Veatch
8400 Ward Parkway
Kansas City, MO 64114

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

JUL 19 2001

RECEIVED
JUL 24 2001
BUREAU OF AIR REGULATION

4 APT-ARB

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

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for the JEA Brandy Branch facility dated April 26, 2001. The draft PSD permit is for the proposed conversion of two simple cycle combustion turbines (CTs) to combined cycle CTs. This project includes the addition of two heat recovery steam generating (HRSG) units with natural gas fired duct burners, a steam turbine generator and a fresh water cooling tower. This project will add 200 megawatts (MW) of electric generating capacity to the 510 MW capacity of the already permitted JEA Brandy Branch facility. The HRSG duct burners will combust pipeline quality natural gas only, and the combined cycle CTs will primarily combust natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the combined cycle CTs will be allowed to fire natural gas up to 8,760 hours per year and fire No. 2 fuel oil a maximum of 288 hours per year. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), and particulate matter (PM/PM_{10}).

The PSD permit to construct the original three simple cycle CTs is dated September 14, 1999. It is our understanding that none of the CTs have begun operating. Therefore, we do not view the proposed conversion as a modification of an existing major source but rather as a change in the design of the entire facility. Accordingly, emissions from the CT that will remain in simple cycle service should be included with emissions from the two converted CTs to assess PSD applicability

Based on our review of the PSD permit application, preliminary determination and draft PSD permit, we have the following comments regarding the BACT analysis and PSD applicability. A comment regarding the air quality impact assessment is provided at the end of this letter.

1. Condition 22 of the draft PSD permit limits emissions of volatile organic compounds (VOC) to 4.8 lb/hour and 8.2 lb/hour when firing natural gas and No. 2 fuel oil, respectively. Table 2-1 (maximum hourly emission rates) of the PSD permit application states the maximum hourly VOC emission rates are 3.49 lb/hour and 7.68 lb/hour when firing natural gas and No. 2 fuel oil, respectively. In order to avoid PSD review for VOC,

the final PSD permit should limit the hourly VOC emission rates to those listed in Table 2-1.

2. Table 2-2 (PSD applicability) of the PSD permit application indicates the potential to emit of sulfur dioxide (SO_2) is based on 0.2 gr/100 scf of sulfur in natural gas and 0.05 percent sulfur by weight in fuel oil. Condition 23 of the draft PSD permit limits the sulfur content of natural gas to 2 gr/100 scf. In order to avoid PSD review for SO_2, the final PSD permit should limit the sulfur content of natural gas to 0.2 gr/100 scf or some other level that ensures emissions of SO_2 do not exceed the PSD significant emissions threshold of 40 tons per year.

3. We are pleased to see that Florida Department of Environmental Protection (FDEP) re-performed the cost analyses for the SCONOx™ and catalytic oxidation add-on control systems. We also questioned a number of items in the applicant's cost evaluation.

In terms of the air quality impact assessment, we have only one comment (below) which has been discussed with FDEP on June 25, 2001.

Project Definition - As discussed above, our view is that the current PSD permit application is not for the modification of an existing major source but an addendum to the PSD permit application. Therefore, the applicable PSD pollutants and air quality impact assessments should include emissions associated with the operation of the two converted combined cycle CTs and the previously permitted simple cycle CT..

Thank you for the opportunity to comment on the JEA Brandy Branch facility preliminary determination and draft permit. If you have any questions regarding these comments, please direct them to either Ms. Katy Forney at 404-562-9130 or Mr. Stan Krivo at 404-562-9123.

Sincerely,

for Gregg M. Worley

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

cc: M. Halpin
C. Holladay
C. Kirts, NED
G. Manning, RESO
J. Bunyak, NPS
B. Oven, DEP Siting
B. Gianazza, JEA

21 West Church Street
Jacksonville, Florida 32202-3139

July 17, 2001

RECEIVED
JUL 19 2001
BUREAU OF AIR REGULATION

JEA

ELECTRIC
WATER
SEWER

David McNeal
U.S. Environmental Protection Agency
Region IV
61 Forsyth Street SW
Atlanta, GA 30303

RE: JEA Brandy Branch Unit 1 (0310485-003-AC, PSD-FL-310)
Request for Extension of Time for Completion of Stack Testing

Dear Mr. McNeal:

On May 20, 2001 Brandy Branch Unit 1 was fired on #2 fuel oil and base loaded. This was the first time the unit ran on liquid fuel with the load greater than 90%. The unit has since experienced problems burning #2 oil.

Per our conversation of this date, we request that an extension of the 60-day window for completing stack testing be granted to allow an additional 720 hours of oil burning within which to complete oil stack testing.

If you have any questions or need additional information, please call me at 904-665-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Permitting
& Compliance Group

cc: A. A. Linero, DEP, BAR
Joe Kahn, DEP, BAR
Richard Banks, DEP, NE District
Robert S. Pace, RESD

7000 0600 0026 4129 9433

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Brandy Branch

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Mr. Walter P. Bussells
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

PS Form 3800, February 2000 | See Reverse for Instructions

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

1 Article Addressed to:

Mr. Walter P. Bussells
Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* T. HEANEY

B. Date of Delivery

C. Signature

X T. Heaney

☐ Agent
☐ Addressee

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

MAY 04 2001

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☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

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BUREAU OF AIR REGULATION

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

32399+2400

Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

April 26, 2001

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. 0310485-003-AC (PSD-FL-310)
Brandy Branch Facility
Combined Cycle Conversion

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 850/921-9519.

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 32234

DEP File No. 0310485-003-AC (PSD-310)
Brandy Branch Facility
Duval County

INTENT TO ISSUE PSD PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration of Air Quality (copy of Draft PSD 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 December 8, 2000 to the Department for a PSD permit to construct a 570 megawatt combined cycle electrical power generating unit consisting of: two (existing) nominal 170 MW "F" class combustion turbine-electrical generators; two supplementally fired heat recovery steam generators capable of raising sufficient steam to generate another 200 MW from a steam-electrical generator; one mechanical draft cooling tower; and ancillary equipment. The project will be located at the existing Brandy Branch facility, approximately 1 mile northeast of Baldwin City in 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 a PSD permit and a determination of Best Available Control Technology for the control of carbon monoxide, nitrogen oxide and particulate matter is required to conduct the work.

The Department intends to issue this PSD 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. and 40 CFR 52.21.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed ""Public Notice of Intent to Issue PSD Permit." The notice shall be published one time only 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). The Department suggests that you publish the notice within thirty days of receipt of this letter. You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit or other authorization. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) 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 permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue PSD permit." Written comments and requests for a public meeting should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE PSD PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT PSD permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/1/01 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
Charles J. Schutty, P.E., Black & Veatch
Mr. Hamilton S. Oven, DEP-Siting

Clerk Stamp

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

Charlotte J. Hayes 5/1/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PSD-FL-310 (PA 00-43)
JEA Brandy Branch
570-Megawatt Combined Cycle Modification
Duval County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to JEA. The permit is to install a combined cycle power-generating unit at the existing Brandy Branch Generating Facility, located approximately 1 mile northeast of Baldwin City, in Duval County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR52.21 for emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO) and nitrogen oxides (NO_X). The applicant's name and address are JEA, 21 West Church Street, Jacksonville, FL 32334.

The project consists of two nominal (existing) 170 MW GE 7FA combustion turbine-electrical generators re-configured for combined cycle operation, operating on natural gas with 0.05% sulfur oil backup (288 hours per year); two 170 million Btu per hour (MMBtu/hr) supplementally-fired (natural gas) heat recovery steam generators (HRSG); one 200 MW (nominal output) steam turbine; one fresh water cooling tower and ancillary equipment.

NO_x emissions are already controlled by Dry Low NO_x combustors to 10.5 parts per million (ppm) while firing natural gas, and by water injection to 42 ppm while firing fuel oil. These technologies, combined with the use of selective catalytic reduction (SCR) systems will reduce NO_X emissions to 3.5 and 15 (ppm for gas and fuel oil firing respectively. Emissions of carbon monoxide (CO) will be controlled to 14 ppm and emissions of sulfur dioxide (SO_2), sulfuric acid mist (SAM), and particulate matter (PM/PM_{10}) will be very low because of the inherently clean fuels.

The following maximum potential annual emissions (in tons per year) summarize the maximum increase in regulated air pollutants as a result of this project.

Pollutants	Maximum Facility Emissions (TPY)
PM/PM_{10}	186
NO_x	233
SO_2	39.5
SAM	5.2
VOC	31.8
CO	465

An air quality impact analysis was conducted. Emissions from the facility will not contribute to or cause a violation of any state or federal ambient air quality standards. All impacts to Class II areas are less than significant. The project is situated approximately 34 kilometers southeast and 127 kilometers southwest of the Okefenokee and Wolf Island Class I National Wilderness Areas, respectively. All impacts to Class I areas are also less than significant.

The Department will issue the FINAL permit with the attached conditions and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) 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 meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue 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 permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

Dept of Environmental Protection	Dept. of Environmental Protection	Jacksonville Regulatory and
Bureau of Air Regulation	Northeast District Office	Environmental Services Department
111 S. Magnolia Drive, Suite 4	7825 Baymeadows Way, Suite 200B	Suite 225, 117 W. Duval Street
Tallahassee, Florida 32301	Jacksonville, Florida 32256-7590	Jacksonville, Florida 32202
Telephone: 850/488-0114	Telephone: 904/448-4300	Telephone: 904/630-3484
Fax: 850/922-6979	Fax: 904/448-4366	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. The Technical Evaluation and Preliminary Determination as well as the Draft BACT Determination and Permit may be viewed at http://www8.myflorida.com/licensingpermitting/learn/environment/air/airpermit.html by clicking on *Utilities and Other Facilities Permits Issued.*

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

JEA

Brandy Branch Generating Facility
570-Megawatt Combined Cycle Modification

Duval County

PSD-FL-310, PA00-43

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

April 26, 2001

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

JEA
21 West Church Street
Jacksonville, FL 32234

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

1.2 Reviewing and Process Schedule

12-08-00: Date of Receipt of Application
01-07-01: Request for Additional Information
03-29-01: Application Complete
04-26-01: Intent to Issue PSD Permit

2. FACILITY INFORMATION

2.1 Facility Location

The JEA Brandy Branch Facility is 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.

See Figures 1 and 2 below.

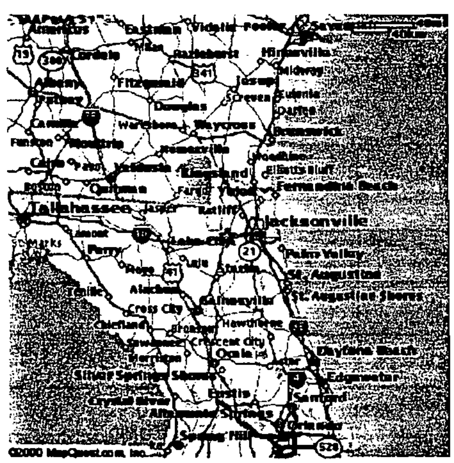

FIGURE 1

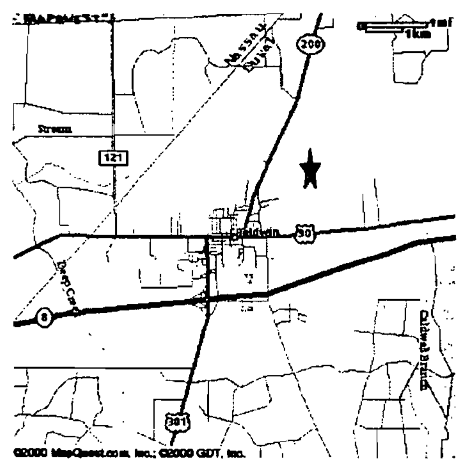

FIGURE 2

2.2 Standard Industrial Classification Codes (SIC)

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

2.3 Facility Category

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. The facility is within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C

As a Major Facility, project emissions greater than the Significant Emission Rates given in Table 212.400-2 (100 TPY of CO; 40 TPY of NO_X, SO_2, or VOC, 25/15 TPY of PM/PM_{10}) require review per the PSD rules and a determination of Best Available Control Technology (BACT). This facility is also subject to the Title IV Acid Rain Program, 40 CFR 72.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	Emission Unit Description
002 *(existing)*	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator re-configured as a combined cycle unit, complete with supplementary fired HRSG
002 *(existing)*	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator re-configured as a combined cycle unit, complete with supplementary fired HRSG
007	Water Cooling	One 10 cell Cooling Tower

JEA proposes to reconfigure the subject two combustion turbine generators (EU-002 and EU-003) to combined cycle. This facility was originally permitted in 1999, via FL-PSD-267, which allowed these emission units to operate only in simple cycle mode. JEA now intends to convert these units to combined cycle operation by the addition of a HRSG, one steam turbine (nominally rated at 200MW) and a cooling tower.

The project includes: two nominal 170 MW GE 7FA combustion turbine-electrical generators re-configured for combined cycle, operating on natural gas with 0.05% sulfur oil backup (288 hours per year); two 170 million Btu per hour (MMBtu/hr) supplementally-fired heat recovery steam generators (HRSG); one 200 MW (nominal output) steam turbine; one fresh water cooling tower and ancillary equipment.

The turbines will be equipped with Dry Low NO_X combustors as well as an SCR in order to control NO_X emissions to 3.5 ppmvd at 15% O_2 while firing natural gas. Each combustion turbine will have a maximum heat input rating of 1,910 (HHV Natural Gas) and 2,060 MMBtu/hr (HHV oil), while the maximum duct burner heat input will be 170.5 MMBtu/hr (HHV Natural Gas). These are specified as cases 7, 16 and 1 (respectively) in the application.

The main fuel will be pipeline quality natural gas and the units will operate up to 8760 hours per year. Emission increases will occur for carbon monoxide (CO), particulate matter (PM/PM_{10}), and nitrogen oxides (NO_X). PSD review is required for CO, PM/PM_{10}, and NO_X, since emissions, per the application, will increase by more than their respective significant emissions levels.

JEA's application was prepared by Black & Veatch.

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 compressor of the 7FA where it is then directed to the combustor section, fuel is introduced, ignited, and burned. The combustion section consists of multiple separate can-annular combustors instead of a single combustion chamber.

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 up to 2700 °F. Energy is recovered within 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.

There are three basic operating cycles for gas turbines. These are simple cycle, regenerative, and combined cycles. In the JEA project, the 7FA will operate in the combined cycle mode and as a continuous duty unit (versus an intermittent duty peaking unit).

In combined cycle operation, the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). In this case, most of the steam is fed to a separate steam turbine, which also drives an electrical generator. Typical combined cycle efficiencies are up to 55 percent. The 7FA can achieve over 50 percent efficiency in combined cycle operation, especially if the gas turbine and the HRSG/steam generator power a common shaft connected to a single electric generator. See Figures 3 and 4 below.

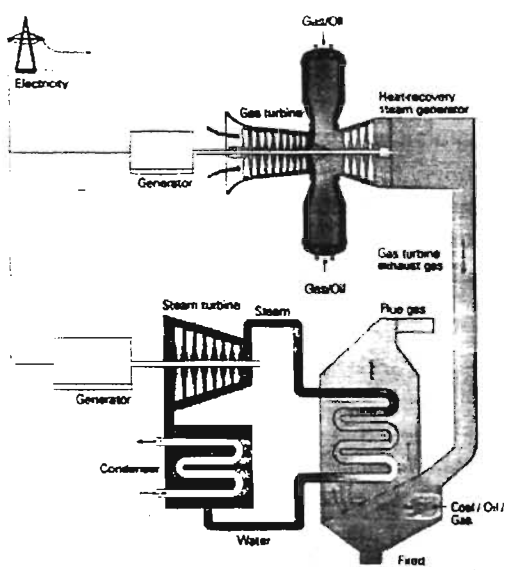

FIGURE 3

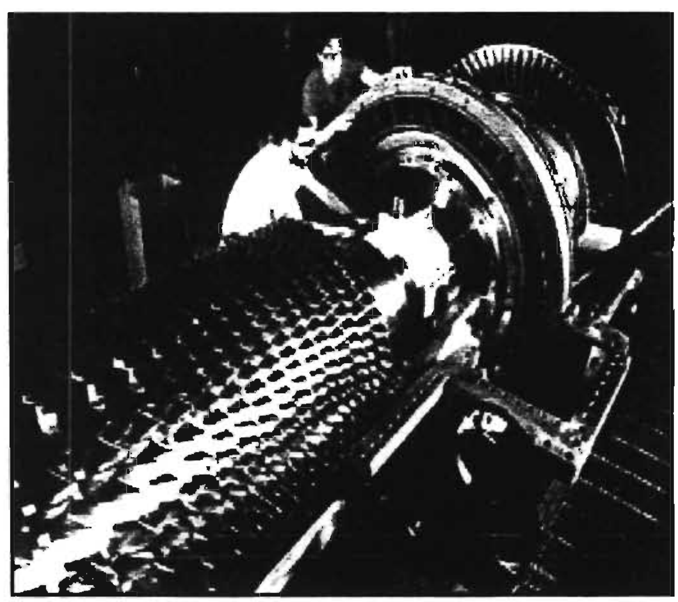

FIGURE 4

Additional process information and control measures to minimize NO_X formation 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 40 CFR 52.21, 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 is 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), because the potential emission increases for PM/PM_{10}, CO, and NO_X exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, CO 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. ***This project will also be reviewed for Site Certification under the Power Plant Siting Act.***

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 62-17	Electrical Power Siting
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	NSPS Subparts GG and Db
40 CFR 60	Applicable sections of Subpart A, General Requirements
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)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide, sulfuric acid mist, and negligible quantities of lead. 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 these Emission Units are summarized in the Draft BACT document and Specific Conditions Nos. 20 through 24 of Draft Permit PSD-FL-310.

6.2 Emission Summary

The emissions for all PSD pollutants as a result of the construction of this facility are presented below:

FACILITY EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutants	2 CT/HRSG with Duct Burners[1]	Cooling Tower	Total	PSD Significance	PSD REVIEW?
PM/PM_{10}	185.6	0.4	186	25	Yes
SO_2	39.5	0	39.5	40	No
NO_X	232.5	0	232.5	40	Yes
CO	465	0	465	100	Yes
Ozone (VOC)	31.8	0	31.8	40	No
Sulfuric Acid Mist	5.2	0	5.2	7	No
Mercury	0.00005	0	0.00005	0.1	No
Lead	0.01	0	0.01	0.6	No
Total HAPS	6.6	0	6.6	10/25	No

1. Based on 8472 hours/year on natural gas at 100% output, 59 °F compressor inlet temperature; 288 hours/year on oil at 100% output at 59°F compressor inlet temperature.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of clean natural gas along with the use of an SCR. The gas turbine combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The SCR will control emissions of NO_X to 3.5 ppm @15% O_2 under normal operating conditions. Low NO_X duct burners will be utilized in the HRSG to achieve NO_X values well under the Subpart Da and Db requirements. 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 Air Quality Analysis Introduction

The proposed project will increase emissions of three regulated pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, NO_2 and CO. PM_{10}, and NO_2 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.

The applicant's initial Class II NO_2, PM_{10}, and CO analyses predicted no significant impacts in the area surrounding the proposed facility; therefore, full impact Class II AAQS and PSD Class II increment analyses were not required for these pollutants. The nearest PSD Class I areas are the Okefenokee (ONWA) and Wolf Island National Wilderness Areas (WINWA) located 34 km northwest and 127 km northeast, respectively. The applicant's PSD Class I air quality analyses showed no significant impacts; therefore cumulative impact analyses were not required in these Class I areas. Also, the maximum predicted impacts for all three pollutants were below their respective *de minimis* ambient impact levels. Therefore, pre-construction monitoring at the proposed site was not required for this project. Based on the preceding discussion, the air quality impact analyses required by the PSD regulations for this project include:

- A Class II significant impact analysis for PM_{10}, NO_2 and CO;
- A Class I significant impact analysis for PM_{10} and NO_2;
- An analysis of impacts on soils, vegetation, and 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 Ambient Monitoring Requirements

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. The monitoring requirement may be satisfied by using existing representative monitoring data, if available. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis concentration. The table below shows that predicted impacts from the combustion turbines are substantially less than the respective de minimis levels; therefore, preconstruction ambient air quality monitoring is not required for any pollutant.

Maximum Project Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4.8	10	NO
CO	8-hour	18	575	NO
NO_2	Annual	0.2	14	NO

6.4.3 Models and Meteorological Data Used in the Air Quality Analysis

6.4.3.1 PSD Class II Area Model

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project will not exceed the good engineering practice (GEP) stack height criteria.

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, operating scenarios, fuels and ambient temperatures in the vicinity of the facility and in portions of the PSD Class I areas located within 50 km of the project. This was accomplished by representing the generating station's proposed operating load range (i.e., 50, 75 and 100 percent loads) with a representative set of stack parameters and pollutant emission rates to produce worst-case plume dispersion conditions and highest model predicted concentrations. This process is referred to as enveloping. The representative stack parameters and emission rates for each load, fuel type and operating scenario were considered in the analysis. 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 upon a visual inspection of the USGS 7.5-minute topographic map of the generating station, it was concluded that over 50% of the area surrounding the generating station is classified as rural. Accordingly, the rural dispersion modeling option was used in the ISCST3 air dispersion modeling.

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, FL and Waycross, GA. 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 most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

6.4.3.2 PSD Class I Area Model

Since portions of the PSD Class I ONWR and WINWR are greater than 50 km from the proposed project, long-range transport modeling was also required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on two Air Quality Related Values (AQRVs): regional haze and deposition of sulfur and nitrogen compounds. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

CALPUFF was first run in screen or 'Lite' mode using ISCST3 meteorological input data. Five years of regionally representative data were used as input. The source of the surface data was the Solar and Meteorological Surface Observation Network (SAMSON) data set that has been produced by the National Climatic Data Center (NCDC). Hourly SAMSON surface data for Jacksonville, Florida supplemented with precipitation data obtained from NCDC for the period 1984 through 1988 was used along with concurrent upper air data from Waycross, Georgia.

Since CALPUFF 'Lite' runs showed significant impacts for at least one pollutant or AQRV in the ONWR, refined CALPUFF modeling was required to further analyze potential impacts. The major difference between CALPUFF 'Lite' and CALPUFF refined modeling is the incorporation of three-dimensional meteorological wind fields. The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. For this project, the CALMET model produced a modeling domain centered over the project location that is approximately 250 km in the north-south direction by 325 km in the east-west direction. This modeling domain was produced by utilizing 1990 meteorological data from 5 upper air, 8 surface, and 35 precipitation stations located throughout north Florida, Georgia and South Carolina.

6.4.4 Significant Impact Analysis

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and Class II Areas. If this modeling at worst load conditions shows significant impacts, additional modeling which includes the emissions from surrounding facilities is required to determine the project's impacts on the existing air quality and any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling.

In order to determine the worst-case emission scenarios, the ISCST3 model in screening mode was used to assess each of the CTG/HRSG operating cases (i.e., a matrix of three CTG loads [100-, 75-, and 50-percent]; three ambient temperatures [20, 59, and 95°F]; and two operating modes [CTG firing natural gas and CTG firing fuel oil] for each pollutant). The worst case operating modes identified by the ISCST3 screening mode for each pollutant were then used as input for the significant impact modeling. This modeling uses ISCST3 in its regular mode. For the Class II analysis a nested rectangular grid of receptors that extends 15-km from the center of the generating station was used. The rectangular grid network consists of 100-m spacing from the proposed fenceline out to 1,000-m; 250-m spacing out from 1-km to 2.5-km; 500-m spacing from 2.5-km out to 5-km and then 1000-m spacing from 5 to 10-km. Receptor spacing of 100-m intervals was used along the fenceline.

ISCST3 was used to evaluate PM_{10} and NO_2 impacts at those portions of the Class I areas (OWNR only) located within 50-km of the proposed site. CALPUFF was used to assess these impacts at those portions of the ONWR and WINWR located beyond 50-km from the proposed site. For the CALPUFF 'Lite' screening analysis four rings of receptors were centered on the facility at distances bracketing the OWNR and WINWR. Receptors were placed at one-degree intervals over a 360-degree arc along each ring. This method simplifies the modeling process while introducing a level of conservatism. 'Lite' results that fell below the significant impact levels did not require a refined CALPUFF run. For results that did not satisfy this demonstration, refined CALPUFF was run. The refined receptor grid consisted of receptors placed at intervals of 2km within the ONWR

The tables below show the results of the significant impact modeling for the Class II and Class I areas.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact?**
PM_{10}	Annual	0.2	1	NO
	24-hr	4.8	5	NO
CO	8-hr	18	500	NO
	1-hr	73	2,000	NO
NO_2	Annual	0.2	1	NO

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (OWNR AND WINWR)						
	NO_X - Annual		**PM_{10} - Annual**		**PM_{10} – 24 hour**	
Class I Area	Max. Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Max. Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Max. Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)
ONWR	0.01	0.1	0.01	0.16	0.22	0.32
WINWR	0.005	0.1	0.005	0.16	0.13	0.32

As shown in the tables there are no maximum predicted air quality impacts due to any emissions from the proposed project which are greater than the PSD significant impact levels. Therefore, under the PSD program, no further air quality impact analysis (PSD increment or AAQS analysis) is required for this project.

6.5 Additional Impacts

6.5.1 Impact Analysis Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from these natural gas-fired combustion turbines in comparison with a conventional power plant generating equal power. Emissions of acid rain and ozone precursors will be very low. An analysis of sulfur and nitrogen deposition impacts in the ONWR and WINWR was done. Based on Federal Land Manager (FLM) criteria, no adverse impacts were predicted. The maximum ground-level concentrations predicted to occur for PM_{10}, CO and NO_X, as a result of the proposed project, including background concentrations and all other nearby sources, will be considerably 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.

6.5.2 Impact On Visibility

Natural gas is a clean fuel and produces little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions (as well as the very low operating hours on 0.05% sulfur oil) will minimize plume opacity. The applicant submitted visibility and regional haze analyses for the ONWR and WINWR. Based on FLM criteria, no adverse visibility and regional haze impacts were predicted.

6.5.3 Growth-Related Air Quality Impacts

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed project and to assess air quality impacts that would result from that growth.

Impacts associated with the combined cycle conversion of Brandy Branch and the associated ancillary equipment will be minor. While not readily quantifiable, the temporary increase in vehicular miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The Brandy Branch conversion is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of the Project are anticipated. The increase in natural gas demand due to increased operation of the two affected CT's (and duct burners) will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

6.5.4 Hazardous Air Pollutants

An analysis supplied by Black & Veatch indicates that the project is not a major source of hazardous air pollutants (HAPs). Accordingly it is not subject to any specific industry or HAP control requirements pursuant to Sections 112 of the Clean Air Act.

7. 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.

Michael P. Halpin, P.E., Review Engineer

Cleve Holladay, Meteorologist

PERMITTEE:

JEA
21 West Church Street
Jacksonville, FL 32234

File No.	PSD-FL-310 (PA00-43)
FID No.	0310485
SIC No.	4911
Expires:	December 31, 2003

Authorized Representative:

Mr. Walter P. Bussells, Managing Director and CEO

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of a nominal 540 megawatt (MW) Combined Cycle generating unit consisting of: two nominal 170 MW, stationary (existing) combustion turbine-electrical generators fired on natural gas and oil; two (new) supplementally-fired heat recovery steam generators (HRSGs); one (new) nominal 200 MW steam electrical generator; one (new) freshwater cooling tower; two (new) selective catalytic reduction units including ancillary equipment and ammonia storage. The combined generating units will achieve approximately 570 megawatts in combined cycle operation during extreme winter peaking conditions. The facility is designated as Brandy Branch Generating Facility and is situated 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.

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).

The attached Appendix is made a part of this permit:

Appendix GC Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

The proposed conversion of two existing combustion turbines at the Brandy Branch Generating Facility will result in a (nominal) 540 MW combined cycle plant. The project includes: two nominal 170 MW GE 7FA combustion turbine-electrical generators re-configured for combined cycle, operating on natural gas with 0.05% sulfur oil backup; two supplementally-fired heat recovery steam generators (HRSG); one 200 MW (nominal output) steam turbine; one fresh water cooling tower and ancillary equipment.

Emissions from the Brandy Branch combined cycle unit will be controlled by Dry Low NO_X (DLN) combustors and selective catalytic reduction (SCR). Clean fuels and good combustion practices will be employed to control all pollutants.

EMISSIONS UNITS

This permit addresses the following emissions units:

EMISSIONS UNIT	SYSTEM	Emission Unit Description
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
003	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine- Electrical Generator configured as a combined cycle unit, complete with supplementary fired HRSG
007	Water Cooling	One 10 cell Cooling Tower

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 within an industry (fossil fuel-fired steam electric plant) included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of NO_X, 25/15 TPY of PM/PM_{10} and 100 TPY of CO. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-310

SECTION I - FACILITY INFORMATION

This project has been submitted as if it is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting. [Chapter 403.503 (12), F.S., Definitions]

This facility is also subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

PERMIT SCHEDULE

- xx/xx/01 PSD Permit Issued
- xx/xx/01 Site Certification Issued
- xx/xx/01 Notice of Intent to Issue PSD Permit published in xxxxxxxxxxxxx
- 04/26/01 Distributed Intent to Issue Permit
- 12/08/00 Received PSD Application

RELEVANT DOCUMENTS:

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

- Department's Final Determination and Best Available Control Technology Determination issued for original project (PSD-FL-267) including PSD permit revisions.
- Application received on December 8, 2000.
- Responses to Sufficiency Items received on March 29, 2001.
- Department's Intent to Issue and Public Notice Package dated April 26, 2001.
- Department's Draft Permit and Draft BACT determination dated April 26, 2001.
- Letter from EPA Region IV dated xx/xx/01.
- Letter from Fish & Wildlife Service dated xx/xx/01.
- Site Certification for the Brandy Branch Generating Facility dated xx/xx/01.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

GENERAL AND 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, F.A.C.]
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) and 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, short-term or annual emission limits, annual fuel heat input limits, changes in methods of operation or similar changes. [40 CFR 52.21(j), 40 CFR 51.166(j) and Rule 62-4.070 F.A.C.]

8. Permit Extension: The permittee, for good cause, may request that this PSD 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. In conjunction with extension of the 18-month periods to commence or continue construction, or extension of the December 31, 2003 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source, at the Department's discretion. [Rule 62-4.080, F.A.C.]
9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]
10. 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.]
11. 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.]
12. 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.]
13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
14. 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.

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, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 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 Emissions Units 002 and 003. Direct Power Generation, each consisting of a nominal 170-megawatt combustion turbine-electrical generator, 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). Additionally, each Emissions Unit consists of a supplementally-fired heat recovery steam generator equipped with a natural gas fired 170 MMBTU/hr duct burner (LHV) and combined with one 200 MW steam electrical generator. The duct burners shall comply with all applicable provisions of 40CFR60, Subpart Db, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.

5. ARMS Emission Unit 007. Cooling Tower, an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because chromium-based chemical treatment is not used.

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

GENERAL OPERATION REQUIREMENTS

7. <u>Fuels</u>: Only pipeline natural gas or fuel oil containing sulfur content of 0.05% or less shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

8. <u>Combustion Turbine Capacity</u>: The maximum heat input rates, based on the higher heating value (HHV) of the fuel to this Unit shall not exceed 1,911 million Btu per hour (MMBtu/hr) when firing natural gas nor 2060 MMBtu/hr when firing oil. This maximum heat input rate will vary depending upon ambient conditions and the combustion turbine characteristics, but shall not exceed these values under any condition. 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. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 170 MMBtu/hour (LHV). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. 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.

11. 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 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.]

12. 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.]

13. 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.]

14. Maximum allowable hours of operation for the 540 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. Fuel oil firing of each combustion turbine is limited to 288 hours per consecutive 12-month period. Unless otherwise authorized by this permit, CT operation below 50% output shall be limited to 2 hours during each calendar day. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

15. Simple Cycle Operation: The plant may not be operated without the use of the SCR system except during periods of startup and shutdown in accordance with the manufacturers requirements.

CONTROL TECHNOLOGY

16. Dry Low NO_X (DLN) combustors shall be installed on each stationary combustion turbine and the permittee shall install a selective catalytic reduction system to comply with the NO_X and ammonia limits listed in Specific Condition 20. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

17. Wet injection shall additionally be installed on each stationary combustion turbine for use during fuel oil firing, in conjunction with the SCR referenced in Specific Condition 16. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

18. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 20 through 24. [Rule 62-4.070, Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

19. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions. A certification following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002-gallons/100 gallons recirculation water flowrate.

EMISSION LIMITS AND STANDARDS

20. Nitrogen Oxides (NO_X) Emissions:

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on natural gas and the duct burner on, shall not exceed 3.5 ppmvd @15% O_2 on a 3-hr block average. The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on fuel oil (duct burner firing not permitted), shall not exceed 15.0 ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]
- Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition 29 for compliance procedures). [Applicant Request, Rule 62-4.070 and 62-204.800(7), F.A.C.]
- The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed 5.0 ppmvd @15% O_2 while firing natural gas, nor 9 ppmvd @ 15%O_2 while firing oil. The compliance procedures are described in Specific Conditions 29 and 45. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]

21. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on any fuel (with duct burners on or off) shall not exceed 14 ppmvd @15% O_2 on a 24-hr block average to be demonstrated by CEMS. [BACT, Rule 62-212.400, F.A.C.]

22. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (baseload at ISO conditions) with the combustion turbine operating on gas shall not exceed 4.8 lb/hour and with the combustion turbine operating on oil shall not exceed 8.2 lb/hr, to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [PSD Avoidance, Rule 62-212.400, F.A.C.]

23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 2 grains per 100 standard cubic foot) and a limited amount of 0.05% sulfur oil. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 40 and 42 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the combustion turbines as well as the duct burners. Note: This will effectively limit the combined SO_2 emissions for EU-002 and EU-003 to approximately 39 tons per year. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.].

24. PM/PM_{10} and Visible emissions (VE): VE emissions shall not exceed 10 percent opacity from the stack in use. PM/PM_{10} emissions from each combustion turbine and HRSG train shall not exceed 20.6 lb/hr at 100% output firing natural gas with the duct burner on and 62.1 lb/hr at 100% output firing fuel oil to be demonstrated by initial stack test using EPA Method 5. [BACT, Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. 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 except during

"warm" or "cold" start-up to combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed in any 24-hour period. During warm startup from combined cycle operation, up to three hours of excess emissions are allowed in any 24-hour period. Cold start-up is defined as a startup to combined cycle operation following a shutdown lasting at least 72 hours. Warm startup is defined as a startup to combined cycle operation following a shutdown lasting at least 24 hours. Startups are defined as being complete when the CT achieves 25% output (40MW Gross). Operation below 50% output per turbine shall otherwise be limited to 2 hours in any 24-hour period. [Rule 62-210.700, F.A.C.].

26. 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. These emissions shall be included in the 3-hr average for NO_X and the 24-hr average for CO.

27. Excess Emissions Report: If excess emissions occur for more than two hours 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, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions 41 through 45, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 20 through 24. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

29. Initial (I) performance tests shall be performed by the deadlines in Specific Condition 28. Initial ~~tests~~ shall also be conducted after any replacement of the major components of the air pollution control equipment (and shake down period not to exceed 100 days after re-starting the CT), such as replacement of SCR catalyst or change of combustors, if specifically requested by the DEP or RESD on a case-by-case basis. 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 these units 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. Where initial tests only are indicated, these tests shall be repeated prior to renewal of each operation permit.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA reference Method 5, "Determination of Particulate Emissions from Stationary Sources." Initial test only.
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A). RATA test data may be used to demonstrate annual compliance.

- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (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); Initial test for compliance with 40CFR60 Subpart GG; Initial (only) NO_X compliance test for the duct burners (Subpart Db) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
- Method CTM-027 for ammonia slip during oil firing (I) and natural gas firing (I, A).

The applicant shall calculate and report the ppmvd ammonia slip (@ 15% O_2) at the measured lb/hr NO_X emission rate as a means of compliance with the BACT standard. The applicant shall also be capable of calculating ammonia slip at the Department's request, according to Specific Condition 45.

30. Continuous compliance with the CO and NO_X emission limits: Continuous compliance with the CO and NO_X emission limits shall be demonstrated by the CEM system on the specified hour average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous period. Specific Condition 41 further describes the CEM system requirements. Excess emissions periods shall be reported as required in Condition 27. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

31. Compliance with the SO_2 and PM/PM_{10} emission limits: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) 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. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. 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) (1998 version).

32. Compliance with CO emission limit: Annual RATA testing for the CO and NO_X CEMS shall be required pursuant to 40 CFR 75.

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

34. Testing procedures: Unless otherwise specified, 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). Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, 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 tests.

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. Compliance Test Reports: 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:

    (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 be 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.

    (4) Daily hours of operation when the CT is being fired and the SCR is not in service, along with support documentation demonstrating that the unit was in a startup or shutdown condition.

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 emissions of NO_X and CO from these emissions units, and the Carbon Dioxide (CO_2) content of the flue gas at the location where NO_X and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_X and CO established in this permit. Compliance with the emission limits for NOx shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. Compliance with the emission limits for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points

collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

The NO_X monitor shall be certified and operated in accordance with the following requirements. The NO_X monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 3 or 24-hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to RESD and the Department's Northeast District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 20 ppm, and the span for the upper range shall not be greater than 100 ppm, as corrected to 15% O_2. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

NO_X, CO and CO_2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit. Periods of data excluded for startup shall not exceed two hours in any block 24-hour period except for "warm" or "cold" startup. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period. Periods of data excluded for warm startup shall not exceed three hours in any 24-hour block period. Periods of data excluded for hot startups, shutdowns or malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all combined startup, shutdown and malfunction episodes shall not exceed four hours in any 24-hour block period. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.

Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.
A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported to RESD and the Department's Northeast District office semi-annually, and shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur.
Upon request from the Department or RESD, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. [Rules 62-4.070(3) and 62-212.400., F.A.C., and BACT]

[Note: Compliance with these requirements will ensure compliance with the other CEM system requirements of this permit to comply with Subpart GG requirements, as well as the applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.7(a)(5) and 40 CFR 60.13, and with 40 CFR Part 51, Appendix P, 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60, Appendix F, Quality Assurance Procedures].

42. Fuel Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within 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 the sole use of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)) for the CT's.
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

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 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).

43. 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. No later than 90 days prior to operation, the permittee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition.

- 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]

44. Subpart Db Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Db].

45. Selective Catalytic Reduction System (SCR) Compliance Procedures:

- An annual stack emission test for nitrogen oxides and ammonia from the CT/HRSG pair shall be simultaneously conducted while firing natural gas and operating with the duct burner on as defined in Specific Condition 20. The ammonia injection rate necessary to comply with the NO_X standard shall be established and reported during each annual performance test.

- The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by manufacturer's guidelines and in accordance with this permit.

- The permittee shall install and operate an ammonia flow meter to continuously measure and record the ammonia injection rate to the SCR system of the CT/HRSG set. It shall be maintained and calibrated according to the manufacturer's specifications.

- During the stack test, the permittee (at each tested load condition) shall determine and report the ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at the ammonia flow rate, which was established during the last stack test.

- Ammonia emissions shall be calculated continuously using inlet and outlet NO_X concentrations from the SCR system and ammonia flow supplied to the SCR system. The calculation procedure shall be provided with the CEM monitoring plan required by 40CFR Part 75. The following calculation represents one means by which the permittee may demonstrate compliance with this condition:

  Ammonia slip @ 15%O_2 = (A-(BxC/1,000,000)) x (1,000,000/B) x D, where:
  A= ammonia injection rate (lb/hr)/ 17 (lb/lb.mol)
  B = dry gas exhaust flow rate (lb/hr) / 29 (lb/lb.mol)
  C = change in measured NO_X (ppmv@15%O_2) across catalyst
  D = correction factor, derived annually during compliance testing by comparing actual to tested ammonia slip

  The calculation along with each newly determined correction factor shall be submitted with each annual compliance test. Calibration data ("as found" and "as left") shall be provided for each measurement device utilized to make the ammonia emission measurement and submitted with each annual compliance test.

- Upon specific request by RESD or the Department, a special re-test shall occur as described in the previous conditions concerning annual test requirements, in order to demonstrate that all NO_X and ammonia slip related permit limits can be complied with.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

JEA Brandy Branch Facility
PSD-FL-310 and 0310485-003-AC
Duval County, Florida

BACKGROUND

The applicant, JEA (formerly Jacksonville Electric Authority) proposes to convert (to combined cycle) two of the three newly installed nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators (CT's) at the Brandy Branch Facility near Baldwin City, Duval County. Past emissions are considered negligible and this project is being permitted as new. 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) and nitrogen oxides (NO_X). 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 project consists of the addition of two supplementary-fired HRSGs, a steam turbine and a cooling tower. JEA proposes to operate each CT/HRSG pair up to 8760 hours per year firing pipeline natural gas, with up to 288 hours of that time firing a 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 April 26, 2001, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on December 8, 2000 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch. Responses to Department questions were received on March 29, 2001 and comprise a part of this review.

REVIEW GROUP MEMBER:

Michael P. Halpin, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	SCR + DLN Combustors (Gas) SCR + Water Injection (Oil)	3.5 ppmvd @ 15% O_2 (gas) 15 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (288 hr/yr) Combustion Controls	10% Opacity
Carbon Monoxide	As Above	12.21 ppmvd (gas, baseload) 14.17 ppmvd (oil baseload)
PM – Cooling Tower	Drift Eliminators	.002 gal/100 gal recirculation flow (equivalent to 0.08 lb/hr PM)

According to the application, the maximum emissions from this project will be approximately 233 tons per year (TPY) of NO_X, 465 TPY of CO and 186 TPY of PM/PM_{10}. Annual emissions of other pollutants are less than the PSD significance thresholds and are itemized in the Technical Evaluation and Preliminary Determination issued on April 26, 2001.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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 units such as those planned for the Brandy Branch combined cycle conversion.

The duct burners required for supplementary gas firing of the HRSG are subject to 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The 0.080 lb/MMBtu NO_X emission rate estimated by JEA is below the Subpart Db limit of 0.20 lb/MMBtu for duct burners used on combined cycle units.

No National Emission Standards for Hazardous Air Pollutants exist for gas-fired duct burners. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines and based upon applicant submittals this project does not require a MACT Determination.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent BACT determinations by states for combined cycle stationary gas turbine projects. These are projects incorporating large prime movers capable of producing more than 150 MW excluding the steam cycle. Such units are typically categorized as F Class Frame units. The applicant's proposed BACT is included for reference.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

TABLE 1

RECENT BACT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	Power Output Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Mobile Energy, AL	~250	~3.5 - NG (CT&DB) ~11 – FO (CT&DB)	DLN & SCR	178 MW GE 7FA CT 1/99 585 MMBtu Duct Burner
KUA Cane Island 3	250	3.5 - (CT&DB)	DLN/SCR	170 MW GE 7FA. 11/99 Ammonia slip = 5 ppmvd
Calpine Osprey	545	3.5 – (CT& DB& PA)	DLN/SCR	Ammonia slip = 9 ppmvd (3 hr avg.)
FPC Hines (PB2)	530	3.5 – NG 12 – FO	DLN/CSR	Ammonia slip = 5 ppmvd gas; Ammonia slip = 9 ppmvd oil
Calpine Bullhead City	545	3.0 – (CT&DB)	DLN/SCR	Replace SCR catalyst after 36 mo.
Calpine Blue Heron	545	3.5 – (CT& DB)	DLN/SCR	Ammonia slip = 5 ppmvd
JEA Brandy Branch (proposed)	570	3.5 – (CT& DB) 15 - FO	DLN/SCR	Ammonia slip ~ 10 ppm

DB = Duct Burner
NG = Natural Gas
FO = Fuel Oil

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection

CT = Comb. Turbine
DB = Duct Burner
PA = Pwr. Augmentation

PA = Power Augmentation
WH = Westinghouse
GE = General Electric

TABLE 2

RECENT BACT LIMITS FOR CARBON MONOXIDE, PARTICULATE MATTER, AND VISIBILITY FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/MMBtu)	PM - lb/MMBtu (or gr/dscf or lb/hr)	Technology and Comments
Mobile Energy, AL	~18 – NG (CT&DB) ~26 – FO (CT&DB)	10% Opacity	Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	10% Opacity	Clean Fuels Good Combustion
Calpine Osprey	10 – NG (CT only) 17 – NG (off-normal)	10% Opacity 24.1 lb/hr (CT & DB)	Clean Fuels Good Combustion
FPC Hines (PB2)	16 – NG 30 – FO	7.3 lb/hr NG 64.8 lb/hr (Fuel Oil)	Clean Fuels Good Combustion
Calpine Bullhead City	10 – NG (CT & DB) 33.9 – NG (DB & PA) 3 hour rolling average	18.3 lb/hr (CT) 22.8 lb/hr (DB & PA)	Clean Fuels Good Combustion
Calpine Blue Heron	10 – NG (CT only) 17 – NG (off-normal)	10% Opacity 26.0 lb/hr (CT & DB)	Clean Fuels Good Combustion
JEA Brandy Branch (proposed)	12.21 – NG (CT & DB) 14.17 – FO	10% Opacity 20.6 lb/hr (CT & DB) 62.1 lb/hr (Fuel Oil)	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, key information reviewed by the Department includes:

- Master Overview for Alabama Power Plant Barry Project received in 1998
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island 3
- Presentations by Black & Veatch and General Electric at EPA Region IV on March 4, 1999
- Texas Natural Resource Conservation Commission Draft Tier I BACT for August, 1999
- Texas Natural Resource Conservation Commission Website – www.tnrcc.state.tx.us
- 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 Kennedy and Brandy Branch Plant CT's
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochures on Duct Burners
- Test data from Tallahassee Purdom No. 8

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. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas, its use is only minimally planned for this project. 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 up to 200 ppmvd @15% O_2 for the JEA turbines. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NO_X emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NO_X control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NO_X emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NO_X emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NO_X emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies.

Combustion Controls

The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel with air prior to combustion in the primary zone. Typically, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% to 100% of base load and provides the lowest NO_X emissions. Due to the intricate air and fuel staging necessary for dry low-NO_X combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%.

Figure A (below) is an example of an in-line duct burner arrangement. Since duct burners operate at lower temperature and pressure than the combustion turbine, the potential for emissions is generally lower. Furthermore the duct burner size for this project is only 170 MMBtu/hr compared with the turbine that can accommodate a heat input greater than 1700 MMBtu/hr (LHV). The duct burners will be of a Low NO_X design and will be used to compensate for loss of capacity at high ambient temperatures.

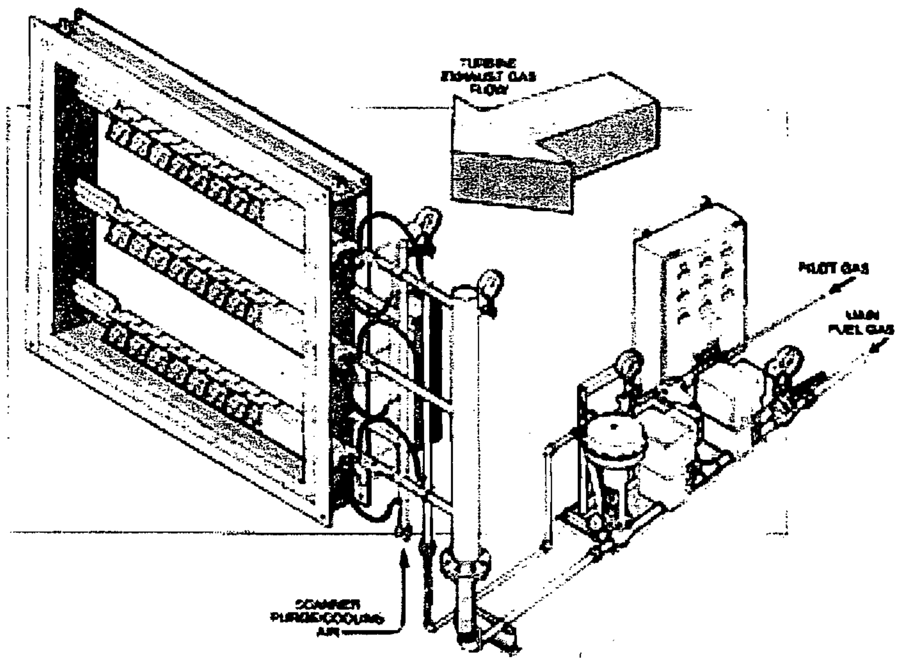

FIGURE A

Selective Catalytic Reduction

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 commonplace and have recently been specified for CPV Gulf Coast (PSD-FL-300). In that review, the Department determined that SCR was cost effective for reducing NO_X emissions from 9 ppmvd to 3.5 ppmvd on a General Electric 7FA unit burning natural gas in combined cycle mode. This review concluded that the unit would be capable of combusting 0.05%S diesel fuel oil for up to 30 days per year while emitting 10ppmvd of NO_X. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, as indicated by Mitsubishi who reports that SCR's are installed on 40 utility boilers which combust *residual* oil. 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.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) currently 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. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3. New combined cycle combustion turbine projects in Florida are normally considered to be prime candidates for SCR, and this is the technology of choice for the Brandy Branch facility, at an estimated cost effectiveness of $4200 per ton (well within current standards).

Figure B is a photograph of FPC Hines Energy Complex. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. Figure C below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met.

Figure B

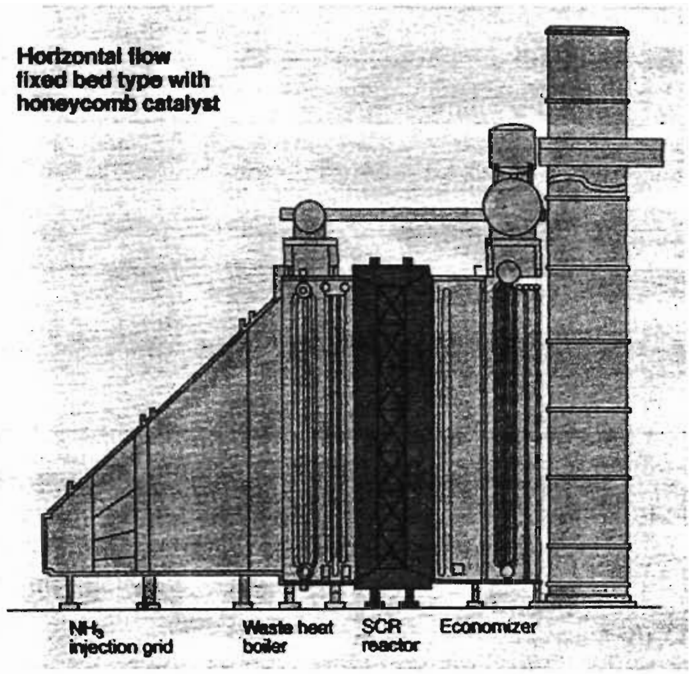

Figure C

Excessive ammonia use tends to increase emissions of ammonia (slip), and particulate matter (when sulfur-bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits at 3.5 ppmvd NO_X (which is proposed for Brandy Branch) are being routinely specified using SCR for F Class projects (with large in-line duct burners) in the Southeast and even lower limits in the southwest.

Selective Non-Catalytic Reduction

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 SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market an SNCR for NO_X control within the temperature ranges for which this project will operate (700 – 1400°F). The process also requires a low oxygen content in the exhaust stream in order to be effective. Given that a top-down review leads to an SCR in this application, SNCR does not merit further consideration.

Emerging Technologies: SCONOx™ and XONON™

SCONOx™ 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 dilute hydrogen 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 permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx ™ [2]. The overall project includes several more 250 MW blocks with SCR for control.[3] According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E Generating has been approved to install SCONOx™ on two F frame units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, 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.

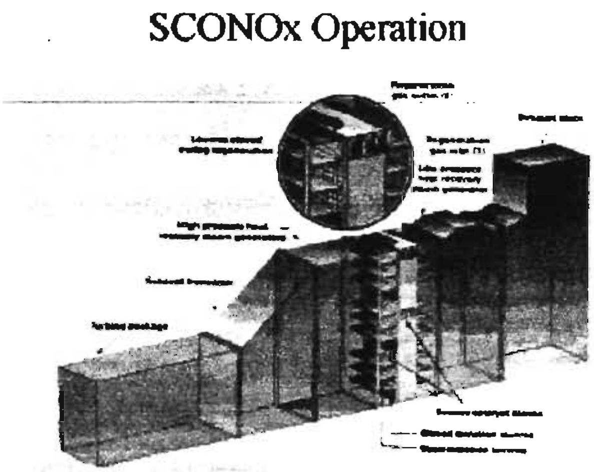

Figure D

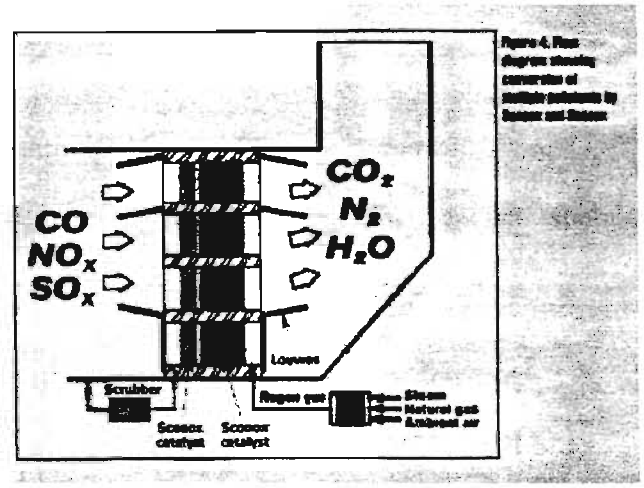

Figure E

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 VOC and CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently only due to cost considerations. The Department is interested in seeing this technology implemented in Florida and intends to continue to work with applicants seeking an opportunity to demonstrate ammonia-free emissions on a large unit. The Department estimates that the application of this control technology to the Brandy Branch Facility results in cost-effectiveness of just less than $10,000 per ton of NO_X removed. Although there are specific items within the applicant's analysis (which estimates a cost effectiveness of $62,000 per ton) that the Department cannot support (e.g. replacement power costs, lost revenues, etc.) on balance the Department concurs with the conclusion that $SCONO_X$ is not likely cost-effective for this project.

Catalytica Energy Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. 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 SCONOx™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

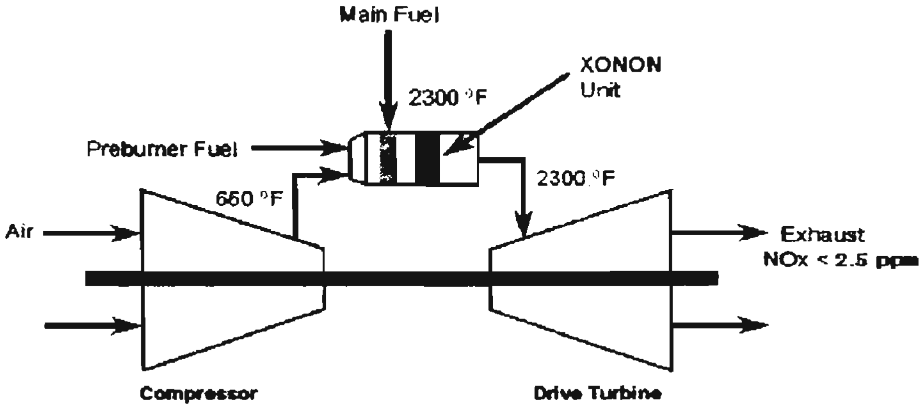

Figure F

XONON-2 installed with test instruments

Figure G

On February 8, 2001, Catalytica Energy Systems, Inc. announced that its XONON™ Cool Combustion system had successfully completed an evaluation process by the U.S. Environmental Protection Agency (EPA), which verified the ultra-low emissions performance of a XONON™-equipped gas turbine operating at Silicon Valley Power. The performance results gathered through the EPA's Environmental Technology Verification (ETV) Program provide high-quality, third party confirmation of XONON™ 's ability to deliver a near-zero emissions solution for gas turbine power production. The verification, which was conducted over a two-day period on a XONON™-equipped Kawasaki M1A-13A (1.4 MW) gas turbine operating at Silicon Valley Power, recorded nitrogen oxides (NO_X) emissions of less than 2.5 parts per million (ppm) and ultra-low emissions of carbon monoxide and unburned hydrocarbons.

The XONON™-equipped Kawasaki M1A-13A gas turbine has operated for over 7400 hours at Silicon Valley Power (SVP), a municipally owned utility, supplying near pollution-free power to the residents of the City of Santa Clara, California, with NO_X levels averaging under 2.5 ppm. Three XONON™-equipped Kawasaki M1A-13X turbines, a slightly modified commercial version of the M1A-13A, are expected to enter commercial service in late 2001 in Massachusetts at a healthcare facility of a U.S. Government agency.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to the commercialization of the XONON™ system for new and existing GE gas turbines. The agreement provides for the collaborative adaptation of XONON™ combustion technology to GE gas turbines for commercial sale. In December 1999, GE accepted the first order for XONON™ -equipped GE 7FA gas turbines as the preferred emission control system for Enron's proposed Pastoria Energy Facility. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. However, the technology cannot (at this time) be recommended for the attendant project.

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 is an inherently clean fuel and contains no ash. Natural gas will be the main fuel fired at the Brandy Branch facility, with a small amount (288 hours per year) of 0.05% Sulfur fuel oil. Both of these fuels are efficiently combusted in gas turbines making any conceivable add-on control technique for PM/PM_{10} unnecessary.

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.

The applicant has identified PM emissions of less than 1 TPY from the cooling tower. Accordingly, drift eliminators shall be installed which shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate. No PM testing is required because the Department's Emission Monitoring Section has determined that there currently is no appropriate PM test method for this type of cooling tower.

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.

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Calpine Sutter in California. The permitted CO values of these units are between 3 and 5 ppmvd. 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 will install oxidation catalyst 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. These installations typically achieve emissions between 9 and 25 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. JEA proposes to meet a limit of 12.21 ppmvd while firing natural gas with the duct burner on. Additionally, the applicant proposes a higher value of 14.17 ppmvd while firing fuel oil.

Test data provided to the Department provides reasonable assurance that the GE 7FA units selected by JEA will achieve values well below those proposed, without requiring installation of an oxidation catalyst, although the estimated cost effectiveness of $2700 per ton is an acceptable cost. The Department will require the use of a CEMS for compliance on a 24-hour block average. Due to the reasonableness of the applicant's proposal, the Department will establish one limit for CO compliance set at 14 ppmvd for all operating modes (gas and oil), and will not impose a further limit on hours of operation as is often done for hours of duct burner firing. However, operating time below 50% output will be restricted as neither emission guarantees nor modeling can support the required emission levels at lower outputs.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the JEA project assuming full load. Values for NO_X and CO are corrected to 15% O_2. The emission limits as well as the applicable averaging times are given in the permit Specific Conditions No. 20 through 24. Annual emissions of SO_2 and VOC should not exceed the PSD Significance levels based upon JEA's proposed emission rates. Accordingly, JEA's proposed emission rates shall become binding limits and placed within the permit in order to ensure that BACT does not apply.

POLLUTANT	CONTROL TECHNOLOGY	BACT DETERMINATION
PM/PM_{10}, VE	Pipeline Natural Gas / 0.05% Sulfur Oil Good Combustion / Inlet Air Filtering	10 Percent Opacity; Note: Will yield approximately 20.6 lb/hr during DB; 62.1 lb/hr during oil firing
CO (all operating modes)	Pipeline Natural Gas / 0.05% Sulfur Oil Good Combustion	14 ppmvd – 24 hour block average
NO_X (all operating modes)	DLN & SCR	3.5 ppmvd (SCR) – 3 hour block average (gas, CT/DB) DB limited to 0.1 lb/MMBtu 15 ppmvd (SCR) – 3 hour block average (oil, no DB) Ammonia slip = 5 ppmvd (gas); 9 ppmvd (oil)
PM (cooling tower)	High efficiency drift eliminators	0.002% drift loss

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd. It has been achieved at a small combustion turbine installation using $SCONO_X$.
- EPA Region IV advised that the Department (in a draft BACT) did not present "any unusual site-specific conditions associated with the KUA Cane Island 3 project to indicate that the use of SCR to achieve 3.5 ppmvd would create greater problems than experienced elsewhere at other similar facilities."[5] The Fish & Wildlife Service had similar comments for Calpine Osprey Energy Center.[9]
- EPA advised FDEP that it intended to appeal the KUA Permit if the Department did not require a NO_X emissions rate of 3.5 ppmvd when firing natural gas.[6]
- FDEP considers a 3-hour averaging time for NO_X compliance and a 5-ppmvd ammonia slip rate to be BACT, as recently determined by CPV Gulf Coast (PSD-FL-300) and Calpine Blue Heron (PSD-FL-309) and other recent combined cycle projects.
- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5 ppmvd).[7]
- For reference, CO limits for the Calpine Blue Heron and FPC Hines projects are 17 ppmvd and 16 ppmvd respectively for all operating modes. Annualized levels above 16 ppmvd on throughputs of "F" machines tend to yield acceptable cost effectiveness values for CO reduction via oxidation catalyst.
- The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT.

Compliance Procedures

POLLUTANT	COMPLIANCE PROCEDURE
PM/Visible Emissions	Method 5 (initial test only) and Method 9 (annually)
Carbon Monoxide	CEMS plus Annual Method 10 during operation at capacity with use of duct burners. Initial Method 10 Test only for oil firing
NO_X 3-hr block average	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 or 7E
Ammonia Slip	CTM-027 initial and annual (The test and analyses shall be conducted so that the minimum detection limit is 1 ppmvd)

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable standard. These excess emissions periods shall be reported as required in Specific Condition 27 of the Permit. A valid hourly emission rate shall be calculated for each hour in which at least two pollutant concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C. and 62-210.700 F.A.C.].

The following emission levels represent excess emission *estimates* during startup and shutdown periods:

STARTUP TYPE	TIME REQUIRED	ESTIMATED EMISSION MAXIMUM LEVELS BY POLLUTANT FOR EACH CT (TOTAL lbm)		
		NO_X	CO	PM
Hot	60 minutes	104	652	18
Warm	129 minutes	283	1360	38
Cold	228 minutes	768	2365	68

The following emissions (TPY) are shown for informational purposes only. They represent a *conservative* estimate of annualized startup emissions, which are largely controllable through best operating practices. Since each startup requires many hours of preceding shutdown time where emissions are zero, there ~~will~~ likely be *no annual net emission increase* from the previously estimated TPY:

STARTUP TYPE	NO. REQUIRED	NO_X	CO	PM
Hot	100	10.4	65.2	1.8
Warm	50	14.2	68	1.9
Cold	10	7.7	23.7	0.7
Total	310	32.2	156.9	4.4

Excess emissions may occur under the following startup scenarios, subject to Rule 62-210.700, F.A.C.:

<u>Hot Start:</u> One hour following a HRSG shutdown less than or equal to 24 hours.

<u>Warm Start:</u> Three hours following a HRSG shutdown greater than 24 hours.

<u>Cold Start:</u> Four hours following a HRSG shutdown greater than or equal to 72 hours.

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E. Review Engineer
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. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[5] Letter. Neeley, R. Douglas, EPA Region IV, to Fancy, C.H., FDEP. Draft PSD Permit – KUA Project. February 2, 1999.

[6] Letter. Smith, Winston, EPA Region IV, to Rhodes, H.L., FDEP. Proposed KUA Permit. November 8, 1999.

[7] Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.

[9.] Letter. Porter, Ellen to Linero, A.A., FDEP. Technical Review of Prevention of Significant Deterioration Permit Application For Osprey Energy Center. April 17, 2000.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

THRU: Al Linero *aaL 4/23*

FROM: Michael P. Halpin *MH*

DATE: April 20, 2001

SUBJECT: JEA Brandy Branch Facility
Combined Cycle Conversion
DEP File No. 0310485-003-AC (PSD-FL-310)

Attached is the public notice package for the conversion of two (previously permitted) dual-fuel 170 MW combustion turbines (CT's) at the existing JEA Brandy Branch Facility. This conversion will allow the emissions of two of the three permitted General Electric CT's to be routed through supplementary fired HRSGs (one for each CT), the steam from which will be sent to one steam turbine rated at approximately 200 MW. Since the combustion turbines have not yet achieved full commercial operation, JEA has submitted the application as if the combined cycle unit will be brand new, in accordance with DEP requirements.

Nitrogen Oxides (NO_X) emissions from the gas turbines will be controlled by Dry Low NO_X (DLN-2.6) plus SCR for gas firing, and water injection plus SCR for oil firing. Emission limits for NO_X will be set at 3.5 ppmvd for gas firing and 15 ppmvd for oil firing. CO emissions will be limited to 14 ppmvd on a 24-hour average by CEMS, regardless of fuel type or mode of operation. The use of fuel oil will be limited to 288 hours per year, which will allow the unit to escape a PSD review for SAM and SO_2.

Emissions of volatile organic compounds and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and the design of the GE unit.

This intent is being issued with the NPS concurrence that JEA's regional haze analysis (for the Class I areas) is satisfactory.

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

AAL/mph

Attachments

PATTY –
HARD COPY
for file.

Memorandum

Florida Department of Environmental Protection

TO: Buck Oven, PPSO

THRU: Clair Fancy, Chief, BAR

THRU: Al Linero, Administrator, NSR Section, BAR *aly*

FROM: Mike Halpin *MH*

DATE: January 16, 2001

SUBJECT: JEA Brandy Branch Repowering
PA 00-43 and PSD-FL-310

Please include the following questions and comments in your Sufficiency package to JEA:

1. Please review and complete the chart (below) in order to clarify the Department's understanding of JEA's proposed BACT analysis for NO_X and CO. The right-hand column is intended to provide the Department with information necessary to analyze only those costs associated with the installation of an oxidation catalyst, which are over and above the cost of installing an SCR. Please specify the capital recovery factors utilized in each configuration, as they are not readily apparent (but appear to be > 0.11). It should be noted that the current version of the EPA's *OAQPS Control Cost Manual* uses an interest rate of 7% versus 9.64%. Additionally, the manual includes a 3% contingency versus the supplied 20% value. Lastly, two values within the economic analysis of the oxidation catalyst system appear suspect:
   a) The annual catalyst replacement cost of $330,000 does not appear to comport with the $664,000 replacement cost and 3 year life guarantee, and
   b) An annual direct cost of $31,000 is shown as a "lost power generation" cost. Although it is appropriate to calculate the cost of using additional natural gas to compensate for the power consumption resulting from the pressure drop across the catalyst bed, lost revenue should not be included in the cost analysis.

   All of the above recommendations should be applied and the economic analysis redone.

Operating Mode	SCR Only	Oxidation catalyst	SCR + Oxidation catalyst	*Differential Cost (over SCR) of Oxidation catalyst* [1]
Total Purchased Equipment Costs	$ 1,709,000	$ 1,139,000	$ 2,558,000	$ 849,000
Direct Installation Costs	$ 513,000	$ 342,000	$ 767,000	$ 254,000
Total Direct Costs Less Catalyst	$ 1,601,000	$ 817,000	$ 2,040,000	$ 439,000
Assumed Catalyst Cost	$ 621,000	$ 664,000	$ 1,285,000	$ 664,000
Total Indirect Capital Costs	$ 820,000	$ 547,000	$ 1,229,000	$ 409,000
Total Capital Costs	$ 3,042,000	$ 2,028,000	$ 4,554,000	$ 1,512,000
Total Direct Annual Costs	$ 448,000	$ 365,000	$ 813,000	$ 365,000
Total Indirect Annual Costs	$ 433,000	$ 237,000	$ 384,000	??
Total Annualized Costs	$ 881,000	$ 602,000	$ 1,197,000	??
Tons Pollutant Removed (TPY)	193.3	209.3	402.6	209.3
Cost Effectiveness ($/ton)	$ 4,600	$ 2,900	$ 3,000	??

[1] *Estimated values prior to JEA's recalculations as requested by FDEP.*

2. The PM BACT Determination for each of the CT's currently permitted at Brandy Branch was 9 lb/hr for gas firing and 17 lb/hr for oil firing. Please reconcile these emission rates with JEA's currently supplied BACT Determination of 19.8 lb/hr for gas firing and 62.1 lb/hr for oil firing.
3. Please confirm that the requested CO emission limits of 54.26 lb/hr (natural gas) and 72.43 lb/hr (oil) are equivalent to 12.21 ppmvd @ 15%O_2 (natural gas, inclusive of supplementary firing) and 14.17 ppmvd (oil) respectively, as BACT emission limits for CO will be set on a ppmvd basis. The Department wishes to point out that recent tests from TECO's Polk Power Station 7FA resulted in CO emissions of less than 1 ppmvd (gas) and less than 2 ppmvd (oil) at full load. Although contracting for CO limits between GE and its customers may not have caught up with field experience, actual results will be considered in the setting of BACT.
4. Please confirm that the data shown in Attachment 2 "Potential-To-Emit (PTE) and Enveloped Spreadsheet" (Combined Natural Gas and Fuel Oil for two turbines) summarizes the maximum emissions of criteria pollutants considering worst-case operating scenarios and all operating modes.
5. Please indicate the maximum gross MW capability of the combined cycle unit, and under what operating conditions this output is achieved. Please provide the same information for the maximum heat input of the CT's as well as duct burners, and the corresponding values under ISO conditions. Maximum requested heat input rates have been specified at1910.2 MMBtu/hr (HHV natural gas) while firing duct burners and 2059.4 MMBtu/hr (HHV oil).
6. Please provide the estimated time frames required and emission levels of NO_X, CO and PM/PM_{10} during hot and cold start-up periods. The Department intends to define these levels in the setting of BACT.
7. The Department requires a project specific cost estimate of a $SCONO_X$ control system, to be supplied by the technology provider (Alstom Power).

We will provide Park Service and EPA comments as soon as they are available. Please advise JEA that they may contact me at 850/921-9519 or Cleve Holladay at 850/921-8986 regarding the above questions.

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 22, 2000

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

RE: JEA Brandy Branch
Combined Cycle Conversion
Facility ID No. 0310485-003-AC, PSD-FL-310

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for construction of a PSD source. The applicant, JEA, proposes to convert two simple cycle electric generating units to a combined cycle configuration at their Brandy Branch facility in Duval County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the review engineer, Mike Halpin, at 850/488-0114.

Sincerely,

Patty Adams

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

AAL/pa

Enclosure

cc: M. Halpin

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 22, 2000

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: JEA Brandy Branch
Combined Cycle Conversion
Facility ID No. 0310485-003-AC, PSD-FL-310

Dear Mr. Worley:

Enclosed for your review and comment is an application for construction of a PSD source. The applicant, JEA, proposes to convert two simple cycle electric generating units to a combined cycle configuration at their Brandy Branch facility in Duval County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the review engineer, Mike Halpin, at 850/488-0114.

Sincerely,

Patty Adams

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

AAL/pa

Enclosure

cc: M. Halpin

HOPPING GREEN SAMS & SMITH
PROFESSIONAL ASSOCIATION
ATTORNEYS AND COUNSELORS
123 SOUTH CALHOUN STREET
POST OFFICE BOX 6526
TALLAHASSEE, FLORIDA 32314
(850) 222-7500
FAX (850) 224-8551
FAX (850) 425-3415
www.hgss.com

Writer's Direct Dial No.
(850) 425-2320

MEMORANDUM

TO: Patty Adams

FROM: Doug Roberts

RE: JEA Site Certification Application - PSD Application

DATE: December 19, 2000

Per your request, attached are the 3 volumes of the PSD Application (Appendix 10.7) for the JEA Brandy Branch Combined Cycle Conversion. Please do not hesitate to call me if you need anything further.

#9

JEA Building Community

MEMORANDUM

JEA Brandy Branch
Combined Cycle Conversion 99262
Site Certification Application manuals/
Site Certification Application;
Appendix 10.7 – PSD Application;
Appendices

December 7, 2000

To: Holders of the JEA/BB Manuals

From: Controlled Documents Center jrw

Project Management has placed these subject manuals under controlled distribution through the Controlled Documents Center.

This memo conveys your assigned copy of the manuals. They are serialized and your name is recorded as the holder. This office will distribute revisions to the manuals; however, keeping the manuals current shall be the responsibility of the individual holder.

Should your job status change and you no longer require these manuals, please return them to the Controlled Documents Center, PGF1 for reassignment.

jrw
Attachment

Name:	Copy Number:
Oven, Hamilton (Buck)	JEA/BB-001 thru 005
Fancy, Clair/App. 10.7 only	JEA/BB-006 thru 009
Hughes, Susan - JEA	JEA/BB-010
Perkins, Tim - JEA	JEA/BB-011
Mims, Eddie - JEA	JEA/BB-012
Gianazza, Bert - JEA	JEA/BB-013
Moser, Steve - JEA	JEA/BB-014
Starner, Lindsay - JEA	JEA/BB-015
Rollins, Myron	JEA/BB-016
Schutty, Chuck	JEA/BB-017
Serafin, Mike	JEA/BB-018
Weiss, Ken	JEA/BB-019
Hillman, Tim - JEA	JEA/BB-020
Gujjarapudi, Ebenezer	JEA/BB-021
Soltys, Mike	JEA/BB-022
Kight, Karen	JEA/BB-023
Project File - Graves, Carolyn	JEA/BB-024
Law Library - Langlois, Jennifer	JEA/BB-025
CDC - Hay, Karen	JEA/BB-026
Roberts, Douglas	JEA/BB-027 thru 028

#7

JEA Building Community

MEMORANDUM

JEA Brandy Branch
Combined Cycle Conversion 99262
Site Certification Application manuals/
Site Certification Application;
Appendix 10.7 – PSD Application;
Appendices

December 7, 2000

To: Holders of the JEA/BB Manuals

From: Controlled Documents Center jrw

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jrw
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Name:	**Copy Number:**
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Hughes, Susan - JEA	JEA/BB-010
Perkins, Tim - JEA	JEA/BB-011
Mims, Eddie - JEA	JEA/BB-012
Gianazza, Bert - JEA	JEA/BB-013
Moser, Steve - JEA	JEA/BB-014
Starner, Lindsay - JEA	JEA/BB-015
Rollins, Myron	JEA/BB-016
Schutty, Chuck	JEA/BB-017
Serafin, Mike	JEA/BB-018
Weiss, Ken	JEA/BB-019
Hillman, Tim - JEA	JEA/BB-020
Gujjarapudi, Ebenezer	JEA/BB-021
Soltys, Mike	JEA/BB-022
Kight, Karen	JEA/BB-023
Project File - Graves, Carolyn	JEA/BB-024
Law Library - Langlois, Jennifer	JEA/BB-025
CDC - Hay, Karen	JEA/BB-026
Roberts, Douglas	JEA/BB-027 thru 028

21 West Church Street
Jacksonville, Florida 32202-3139

RECEIVED

AUG 03 2001

BUREAU OF AIR REGULATION

August 2, 2001

JEA

Mr. Mike Halpin
Department of Environmental Protection
2600 Blair Stone Rd
Mail Station 5505
Tallahassee, FL. 32399-2400

ELECTRIC

WATER

SEWER

Dear Mr. Halpin:

RE: Source Test Reports
Brandy Branch Generating Station

I am enclosing for your review initial stack test reports for Brandy Branch Units 1 and 2.

Should you have any questions, please contact me at (904) 665-5501.

Sincerely,

David Norse

David Norse
Environmental Permitting
& Compliance Group

Enclosure

21 West Church Street
Jacksonville, Florida 32202-3139

RECEIVED
MAY 23 2001
BUREAU OF AIR REGULATION

JEA

ELECTRIC

WATER

SEWER

May, 22 2001

Mr. Mike Halpin
Department of Environmental Protection
Division of Air Resource Management
Twin Towers Office Building - MS 5505
2600 Blair Stone Road
Tallahassee, FL. 32399-2400

Dear Mr. Halpin:

RE: Public Notification
Brandy Branch

I am enclosing for your review the public notice for a PSD permit to be issued to JEA for the conversion of two simple cycle turbines to combined cycle operation at the existing Brandy Branch Generating Facility.

Should you have any questions, please contact me at (904) 665-5501.

Sincerely,

David Norse

David Norse
Environmental Permitting
& Compliance Group

Enclosure

cc: C. Kirts, NED
G. Manning, EESD
G. Worley, EPA
J. Bunyak, NPS
B. Oven DEP
C. Holladay

THE FLORIDA TIMES-UNION
Jacksonville, Fl
Affidavit of Publication

Florida Times-Union

J.E.A./ENVIRONMENTAL
ATTN: DAVE ENGLISH
21 W CHURCH ST T-8
JACKSONVILLE FL 32202

REFERENCE: 0334984
R42959 PUBLIC NOTICE OF INT

State of Florida
County of Duval

Before the undersigned authority personally appeared Elizabeth Heisler who on oath says she is a Legal Advertising Representative of The Florida Times-Union, a daily newspaper published in Jacksonville in Duval County, Florida; that the attached copy of advertisement is a legal ad published in The Florida Times-Union. Affiant further says that The Florida Times-Union is a newspaper published in Jacksonville, in Duval County, Florida, and that the newspaper has heretofore been continuously published in Duval County, Florida each day, has been entered as second class mail matter at the post office in Jacksonville, in Duval County, Florida for a period of one year preceeding the first publication of the attached copy of advertisement; and affiant further says that he/she 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.

PUBLISHED ON: 05/18

FILED ON: 05/18/01 Elizabeth J. Heisler

Name: Elizabeth Heisler Title: Legal Advertising Representative
In testimony whereof, I have hereunto set my hand and affixed my official seal, the day and year aforesaid.

NOTARY: Joan Miller

OFFICIAL NOTARY SEAL
JOAN MILLER
NOTARY PUBLIC STATE OF FLORIDA
COMMISSION NO. CC996195
MY COMMISSION EXP. JAN. 23,2005

Legal Notices

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. PSD-FL-310 (PA 00-43)
JEA Brandy Branch
570-Megawatt Combined Cycle Modification
Duval County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to JEA. The permit is to convert two existing simple cycle turbines to combined cycle operation at the existing Brandy Branch Generating Facility, located approximately 1 mile northeast of Baldwin City, in Duval County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR52.21 for emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO) and Nitrogen oxides (NOx). The applicant's name and address are JEA, 21 West Church Street, Jacksonville, FL 32334.

The project consists of two nominal (existing) 170 MW GE 7FA combustion turbine-electrical generators reconfigured for combined cycle operation, operating on natural gas with 0.05% sulfur oil backup (288 hours per year); two 85 million Btu per hour (MMBtu/hr) suplementally-fired (natural gas) heat recovery steam generators (HRSG); one 200 MW (nominal output) steam turbine; one fresh water cooling tower and ancillary equipment.

NOx emissions are already controlled by Dry Low NOx combustors to 10.5 parts per million (ppm) while firing natural gas, and by water injection to 42 ppm while firing fuel oil. These technologies, combined with the use of selective catalytic reduction (SCR) systems will reduce NOx emissions to 3.5 and 15 (ppm for gas and fuel oil firing respectively). Emissions of carbon monoxide (CO) will be controlled to 14 ppm and emissions of sulfur dioxide (SO_2), sulfuric acid mist (SAM), and particulate matter (PM/PM10) will be very low because of the inherently clean fuels.

The following maximum potential annual emissions (in tons per year) summarize the maximum increase in regulated air pollutants as a result of this project.

Pollutants	Maximum Project Emmissions (TPY)
PM/PM10	186
NO_x	233
SO_2	39.5
SAM	5.2
VOC	31.8
CO	465

An air quality impact analysis was conducted. Emissions from the facility will not contribute to or cause a violation of any state or federal ambiant air quality standards. All impacts to Class II areas are less than significant. The project is situated approximately 34 kilometers southeast and 127 kilometers southwest of the Okefenokee and Wolf Island Class I National Wilderness Areas, respectively. All impacts to Class I areas are also less than significant.

The Departmet will issue the FINAL permit with the attached conditions and after approval of the certification pursuant to the Florida Power Plant Siting Act (Sections 403.501-519, F.S.) 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 meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to issue 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 permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

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

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

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

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

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

Dept. of Environmental Protection
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, Florida 32256-7590
Telephone: 904/488-4300
Fax: 904/448-4366

Jacksonville Regulatory and
Environmental Services Department
Suite 225, 117 W. Duval Street
Jacksonville, Florida 32202
Telephone: 904/630-4900
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. The Technical Evaluation and Preliminary Determination as well as the Draft BACT Determination and permit may be viewed at:
http:\www8.myflorida.com/licensingpermitting/learn/environment/air/airpermit.html by clicking on Utilities and Other Facilities Permits Issued.