SITE CERTIFICATION APPLICATION

Appendix 10.7 – PSD Application

JEA Brandy Branch Combined Cycle Conversion

Building Community

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

Issued 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

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 μg/m³, which is just under the SIL of 5 μg/m³. 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

CH Fancy 3/28/02

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

"More Protection, Less Process"

Printed on recycled paper.

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.

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.

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.

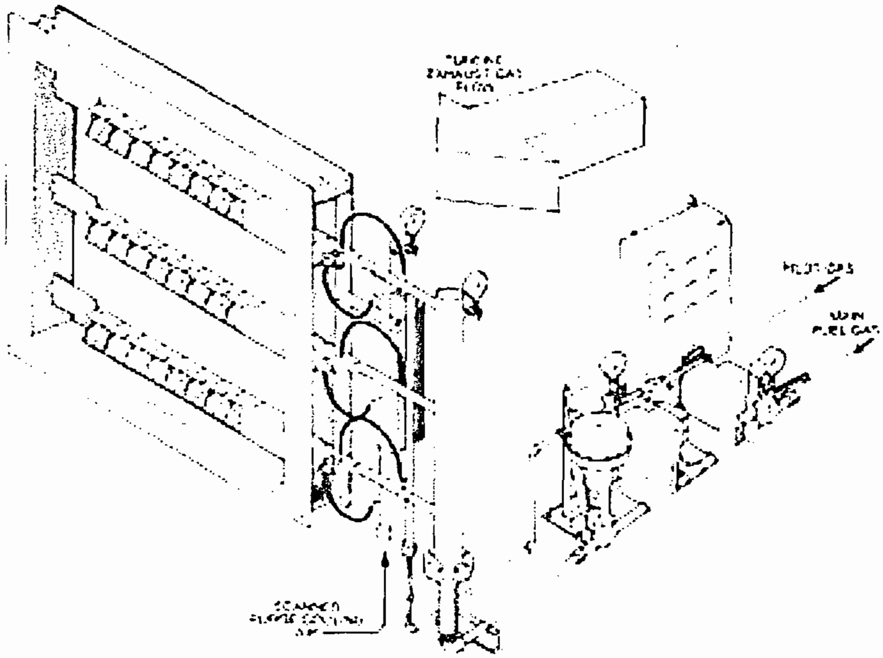


FIGURE A

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.

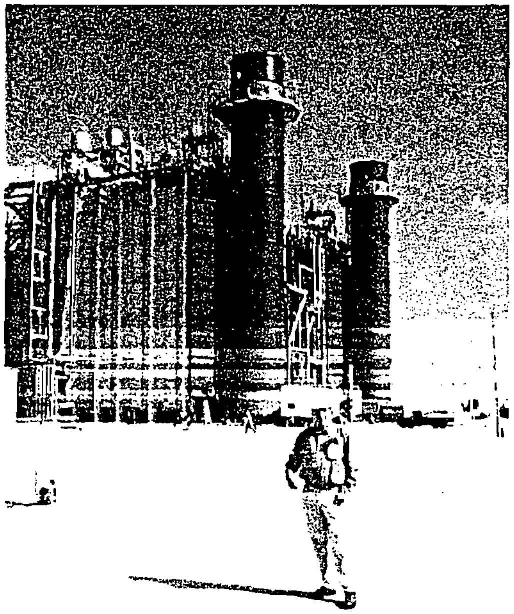


Figure B

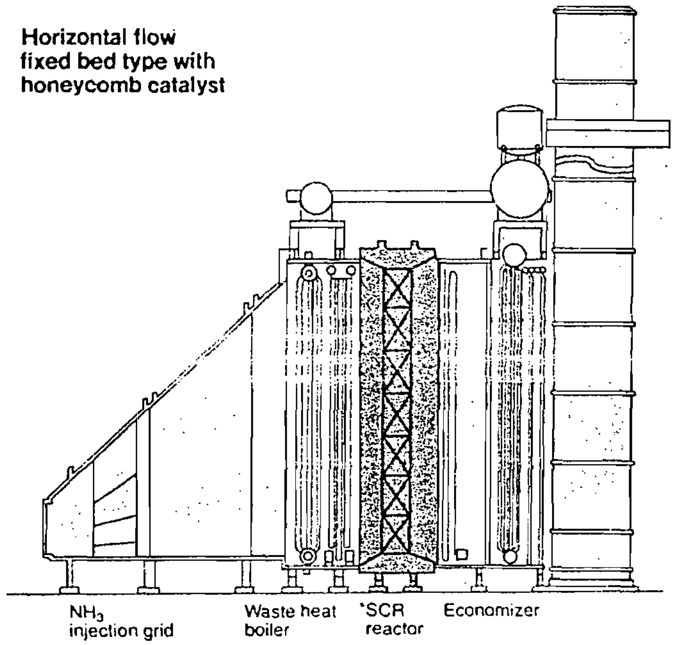


Figure C

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.

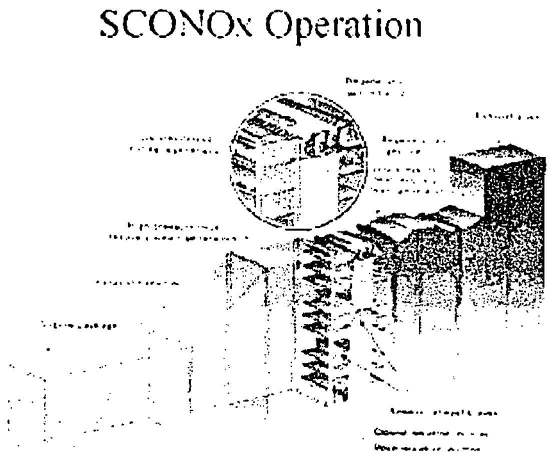


Figure D

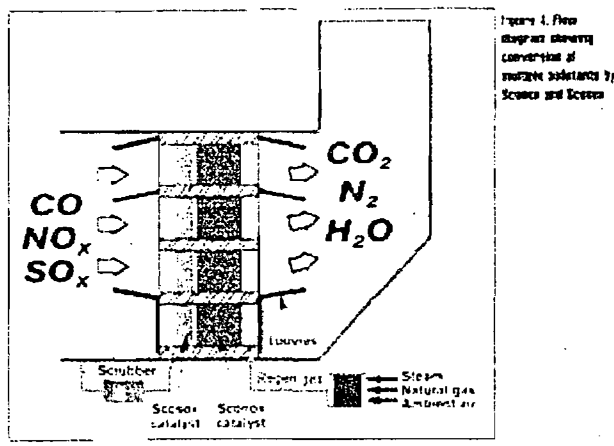


Figure E

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.

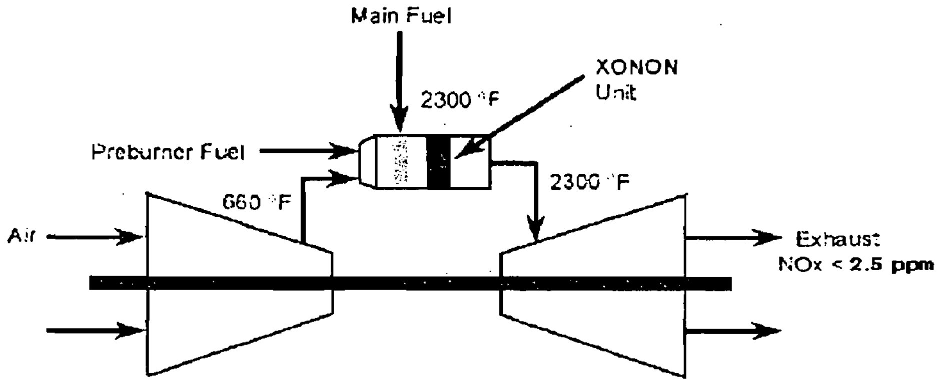
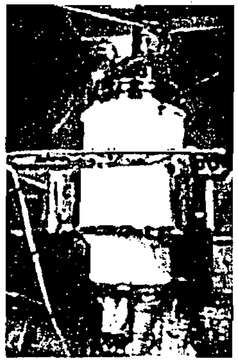


Figure F



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

Recommended By:

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

3/28/02
Date:

Approved By:

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.