STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. A. K. Sharma, Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741-6804

Facility I.D. No. 0970043
DRAFT Permit No.: PSD-FL-254
Cane Island Power Park Unit 3
Osceola County

_______________________________________/

Enclosed is the Final Permit Number PSD-FL-254 to construct: a nominal 250 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine-electrical generator; a supplementally-fired heat recovery steam generator; a steam electrical generator; a 1.0 million gallon fuel oil storage tank; ammonia storage; 130-foot main stack; and a 100-foot bypass stack at the Kissimmee Utility Authority Cane Island Power Park at 6075 Old Tampa Highway, Osceola 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.

CH Fancy

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail* and copies were mailed by U.S. Mail before the close of business on 11-24-99 to the person(s) listed:

A. K. Sharma, KUA*
Jeff Ling, KUA
Gregg Worley, EPA
John Bunyak, NPS
Len Kozlov, DEP CD
Buck Oven, DEP PPSO
D. D. Schultz, P.E., Black & Veatch
Tasha Buford, Esq., YVVA, P.A.

Clerk Stamp

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

Kim Tober 11-24-99
(Clerk) (Date)

Z 031 392 023

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KUA
1701 W. Carroll St.
Kissimmee, Fl
34741-6804

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Title 40--Protection of Environment

CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY

124--PROCEDURES FOR DECISIONMAKING

life of a RCRA hazardous waste management facility or unit under § 270.29). The Regional Administrator shall notify the applicant and each person who has submitted written comments or requested notice of the final permit decision. This notice shall include reference to the procedures for appealing a decision on a RCRA, UIC, or PSD permit or for contesting a decision on an NPDES permit or a decision to terminate a RCRA permit. For the purposes of this section, a final permit decision means a final decision to issue, deny, modify, revoke and reissue, or terminate a permit.

(b) A final permit decision (or a decision to deny a permit for the active life of a RCRA hazardous waste management facility or unit under § 270.29) shall become effective 30 days after the service of notice of the decision unless:

(1) A later effective date is specified in the decision; or

(2) Review is requested under § 124.19 (RCRA, UIC, and PSD permits) or an evidentiary hearing is requested under § 124.74 (NPDES permit and RCRA permit terminations); or

(3) No comments requested a change in the draft permit, in which case the permit shall become effective immediately upon issuance.

[48 FR 14264, Apr. 1, 1983, as amended at 54 FR 9607, Mar. 7, 1989]

§ 124.16 Stays of contested permit conditions.

(a) *Stays.* (1) If a request for review of a RCRA or UIC permit under § 124.19 or an NPDES permit under § 124.74 or § 124.114 is granted or if conditions of a RCRA or UIC permit are consolidated for reconsideration in an evidentiary hearing on an NPDES permit under §§ 124.74, 124.82 or 124.114, the effect of the contested permit conditions shall be stayed and shall not be subject to judicial review pending final agency action. (No stay of a PSD permit is available under this section.) If the permit involves a new facility or new injection well, new source, new discharger or a recommencing discharger, the applicant shall be without a permit for the proposed new facility, injection well, source or discharger pending final agency action. See also § 124.60.

(2) Uncontested conditions which are not severable from those contested shall be stayed together with the contested conditions. Stayed provisions of permits for existing facilities, injection wells, and sources shall be identified by the Regional Administrator. All other provisions of the permit for the existing facility, injection well, or source shall remain fully effective and enforceable.

(b) *Stays based on cross effects.* (1) A stay may be granted based on the grounds that an appeal to the Administrator under § 124.19 of one permit may result in changes to another EPA-issued permit only when each of the permits involved has been appealed to the Administrator and he or she has accepted each appeal.

(2) No stay of an EPA-issued RCRA, UIC, or NPDES permit shall be granted based on the staying of any State-issued permit except at the discretion of the Regional Administrator and only upon written request from the State Director.

(c) Any facility or activity holding an existing permit must:

(1) Comply with the conditions of that permit during any modification or revocation and reissuance proceeding under § 124.5; and

(2) To the extent conditions of any new permit are stayed under this section, comply with the conditions of the existing permit which correspond to the stayed conditions, unless compliance with the existing conditions would be technologically incompatible with compliance with other conditions of the new permit which have not been stayed.

§ 124.17 Response to comments.

(a) *(Applicable to State programs, see §§ 123.25 (NPDES), 145.11 (UIC), 233.26 (404), and 271.14 (RCRA).)* At the time that any final permit decision is issued under § 124.15, the Director shall issue a response to comments. States are only required to issue a response to comments when a final permit is issued. This response shall:

(1) Specify which provisions, if any, of the draft permit have been changed in the final permit decision, and the reasons for the change; and

(2) Briefly describe and respond to all significant comments on the draft permit or the permit application (for section 404 permits only) raised during the public comment period, or during any hearing.

(b) For EPA-issued permits, any documents cited in the response to comments shall be included in the administrative record for the final permit decision as defined in § 124.18. If new points are raised or new material supplied during the public comment period, EPA may document its response to those matters by adding new materials to the administrative record.

(c) *(Applicable to State programs, see §§ 123.25 (NPDES), 145.11 (UIC), 233.26 (404), and 271.14 (RCRA).)* The response to comments shall be available to the public.

§ 124.18 Administrative record for final permit when EPA is the permitting authority.

(a) The Regional Administrator shall base final permit decisions under § 124.15 on the administrative record defined in this section.

(b) The administrative record for any final permit shall consist of the administrative record for the draft permit and:

(1) All comments received during the public comment period provided under § 124.10 (including any extension or reopening under § 124.14);

(2) The tape or transcript of any hearing(s) held under § 124.12;

(3) Any written materials submitted at such a hearing;

(4) The response to comments required by § 124.17 and any new material placed in the record under that section;

(5) For NPDES new source permits only, final environmental impact statement and any supplement to the final EIS;

(6) Other documents contained in the supporting file for the permit; and

(7) The final permit.

(c) The additional documents required under paragraph (b) of this section should be added to the record as soon as possible after their receipt or publication by the Agency. The record shall be complete on the date the final permit is issued.

(d) This section applies to all final RCRA, UIC, PSD, and NPDES permits when the draft permit was subject to the administrative record requirements of § 124.9 and to all NPDES permits when the draft permit was included in a public notice after October 12, 1979.

(e) Material readily available at the issuing Regional Office, or published materials which are generally available and which are included in the administrative record under the standards of this section or of § 124.17 ("Response to comments"), need not be physically included in the same file as the rest of the record as long as it is specifically referred to in the statement of basis or fact sheet or in the response to comments.

§ 124.19 Appeal of RCRA, UIC, and PSD permits.

(a) Within 30 days after a RCRA, UIC, or PSD final permit decision (or a decision under § 270.29 to deny a permit for the active life of a RCRA hazardous waste management facility or unit) has been issued under § 124.15, any person who filed comments on that draft permit or participated in the public hearing may petition the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments or failed to participate in the public hearing 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 30-day period within which a person may request review under this section begins with the service of notice of the Regional Administrator's action unless a later date is specified in that notice. The petition shall include a statement of the reasons supporting that review, including a demonstration that any issues being raised were raised during the public comment period (including any public hearing) to the extent required by these regulations and when appropriate, a showing that the condition in question is based on:

(1) A finding of fact or conclusion of law which is clearly erroneous, or

(2) An exercise of discretion or an important policy consideration which the

Environmental Appeals Board should, in its discretion, review.

(b) The Environmental Appeals Board may also decide on its initiative to review any condition of any RCRA, UIC, or PSD permit issued under this part. The Environmental Appeals Board must act under this paragraph within 30 days of the service date of notice of the Regional Administrator's action.

(c) Within a reasonable time following the filing of the petition for review, the Environmental Appeals Board shall issue an order granting or denying the petition for review. To the extent review is denied, the conditions of the final permit decision become final agency action. Public notice of any grant of review by the Environmental Appeals Board under paragraph (a) or (b) of this section shall be given as provided in § 124.10. Public notice shall set forth a briefing schedule for the appeal and shall state that any interested person may file an amicus brief. Notice of denial of review shall be sent only to the person(s) requesting review.

(d) The Environmental Appeals Board may defer consideration of an appeal of a RCRA or UIC permit under this section until the completion of formal proceedings under subpart E or F relating to an NPDES permit issued to the same facility or activity upon concluding that:

(1) The NPDES permit is likely to raise issues relevant to a decision of the RCRA or UIC appeals;

(2) The NPDES permit is likely to be appealed; and

(3) *Either:* (i) The interests of both the facility or activity and the public are not likely to be materially adversely affected by the deferral; or

(ii) Any adverse effect is outweighed by the benefits likely to result from a consolidated decision on appeal.

(e) A petition to the Environmental Appeals Board under paragraph (a) of this section is, under 5 U.S.C. 704, a prerequisite to the seeking of judicial review of the final agency action.

(f)(1) For purposes of judicial review under the appropriate Act, final agency action occurs when a final RCRA, UIC, or PSD permit is issued or denied by EPA and agency review procedures are exhausted. A final permit decision shall be issued by the Regional Administrator:

(i) When the Environmental Appeals Board issues notice to the parties that review has been denied;

(ii) When the Environmental Appeals Board issues a decision on the merits of the appeal and the decision does not include a remand of the proceedings; or

(iii) Upon the completion of remand proceedings if the proceedings are remanded, unless the Environmental Appeals Board's remand order specifically provides that appeal of the remand decision will be required to exhaust administrative remedies.

(2) Notice of any final agency action regarding a PSD permit shall promptly be published in the FEDERAL REGISTER.

(g) Motions to reconsider a final order shall be filed within ten (10) days after service of the final order. Every such motion must set forth the matters claimed to have been erroneously decided and the nature of the alleged errors. Motions for reconsideration under this provision shall be directed to, and decided by, the Environmental Appeals Board. Motions for reconsideration directed to the administrator, rather than to the Environmental Appeals Board, will not be considered, except in cases that the Environmental Appeals Board has referred to the Administrator pursuant to § 124.2 and in which the Administrator has issued the final order. A motion for reconsideration shall not stay the effective date of the final order unless specifically so ordered by the Environmental Appeals Board.

[48 FR 14264, Apr. 1, 1983, as amended at 54 FR 9607, Mar. 7, 1989; 57 FR 5335, Feb. 13, 1992]

§ 124.20 Computation of time.

(a) Any time period scheduled to begin on the occurrence of an act or event shall begin on the day after the act or event.

(b) Any time period scheduled to begin before the occurrence of an act or event shall be computed so that the period ends on the day before the act or event.

(c) If the final day of any time period falls on a weekend or legal holiday, the time period shall be extended to the next working day.

FINAL DETERMINATION
KISSIMMEE UTILITY AUTHORITY
CANE ISLAND UNIT 3
COMBINED CYCLE COMBUSTION TURBINE

The Department distributed a Public Notice package on January 7, 1999 for the project to construct a 250 megawatt (MW) natural gas and fuel oil-fired combined cycle unit at the Kissimmee Utility Authority (KUA) Cane Island Power Plant located in Intercession City, Osceola County. The project includes: a 167 MW combustion turbine; a heat recovery steam generator with supplemental duct burners; a 1 million gallon fuel oil storage tank; a 130-foot stack; and a 100-foot stack for simple cycle operation. The Public Notice of Intent to Issue was published on January 9 in The Orlando Sentinel.

No comments were received by the Department from the public or the Fish and Wildlife Service pursuant to the Notice. However the Fish and Wildlife Service submitted substantial comments on the original application. These were considered prior to issuance of the Public Notice package.

Comments were received from the U.S. Environmental Protection Agency (EPA) in a letter dated February 2 (corrected version received March 15). Fairly minimal comments were received from KUA in a letter dated February 3. A letter dated February 16 was received from EPA approving the Custom Fuel Monitoring Request proposed in the Public Notice Package. Additional comments in response to EPA's letter of February 2 were received from KUA in the form of a presentation to the Department and EPA in Atlanta on March 4. The presentation was followed up by a letter to EPA on March 10 and another letter to EPA and the Department dated March 24.

On March 29 the Department prepared an interim revision of the package for inclusion in the record for consideration by the Administrative Law Judge at an uncontested hearing pursuant to the Site Certification requirements in 403.501-519, Florida Statutes. That version was included in the Recommended Order that was considered and approved by the Governor and Cabinet on November 9. The Final Order was issued on November 22. The rules require final action on the PSD Permit within 30 days after issuance of the Final Site Certification Order.

The Department met with EPA in Tallahassee on November 5 to discuss the status of various pending PSD permit applications for combined cycle units. The KUA project was discussed at that time. A subsequent meeting was held between the Department and KUA on November 10 prior to final action on the application.

The main comments were from EPA. All are related to the rationale given on page 12 of the Department's original draft determination of Best Available control Technology (BACT) dated January 7.

1. *In its letter dated February 2, EPA states that the "State has indicated that the cost of achieving 3.5 ppm for the KUA project is comparable with the costs reported by Southern Company for recent similar projects in Alabama and Mississippi.*

   In its revised draft BACT document dated March 29, the Department noted that the reports from Southern Company were <u>unconfirmed</u>. When subsequently asked, a Company representative would not provide any written cost information and ultimately said that they extrapolated from a project for a smaller unit in Alabama. He stated that the Company had not in fact made a cost-effectiveness estimate for projects in Alabama and Mississippi most similar to the KUA project.

More recently, an affiliate of Southern Company provided the Department with a memorandum explaining that Southern Company had actually proposed a technology and emission limit equal to the Lowest Achievable Emission Rate such as required in non-attainment areas. The memo explained that LAER is the "top" technology and that upon proposing it, no further "top/down" analyses, costs or other details are required. The affiliate also provided the Department with a copy of Southern Company's application to the State of Alabama. The application itself confirmed the rationale. A review of Alabama's technical analysis for the project indicated that they did not perform a cost analysis. This is consistent with the rationale discussed above. It is noteworthy that another Southern Company affiliate subsequently proposed a BACT NO_X emission limit of 9 ppmvd by DLN technology for two combined cycle projects in Texas.

KUA through Black and Veatch (B&V) supplied an updated cost analysis at the March 4 presentation of $5,452 per ton of NO_X removed assuming ammonia slip of 10 ppmvd. KUA estimated a cost effectiveness value of $16,056 per ton of pollutant removed to achieve 3.5 ppmvd if the *increases* in ammonia are subtracted from the decreases in NO_X. General Electric provided much higher estimates in their own short presentation.

The Department does not dispute the KUA estimate of $5,452 per ton of NO_X removed, but notes that it is probably low because the Department (through the Site Certification process) included a limit of 5 ppmvd of ammonia slip under the SCR option for this project per the March 19 BACT revision. The Department appreciates the effort by KUA to assess the cost of total pollutant decrease, but the procedure was rejected by EPA at the meeting and the Department does not recognize it. These extra costs are valid considerations within the "other energy, economic, and environmental" impacts that the Department can consider in making a final decision.

2. *The EPA letter states that "due to the negative effects of using SCR, (which includes increased particulate emissions, undesirable ammonia emissions, and energy penalties), the State believes that the use of DLN and low NO_X burners to achieve a combined CT/duct burner emission limit of 9.4 is justifiable. Although these are valid concerns, they do not necessarily indicate that the use of SCR to achieve NO_X emissions of 3.5 ppm would create greater problems than experienced elsewhere at other facilities"*

The Department does not dispute the statement. However the Department has concluded that SCR for this project is not actually cost-effective per the conventional marginal cost methodology. Per EPA, the additional concerns are apparently valid and, in the opinion of the Department, further buttress the rationale for allowing the applicant to use DLN to achieve 9 ppmvd NO_X in lieu of SCR to achieve lower emissions.

In its presentation of March 4 and subsequent letter of March 24, KUA (through B&V) detailed the adverse impacts of ammonia use. These include ammonia slip, risk management, public concern, transportation, catalyst disposal, operational back-pressure/lower energy production, ammonium bisulfate deposits on the heat recovery surfaces, maintenance of pumps, measurement uncertainties, etc. The Department does not dispute the assertions made by KUA, but agrees with EPA that it has not been shown that these "create greater problems than experienced elsewhere at other facilities." The Department does believe that these are still valid concerns. They are experienced at many sites and the risks and costs are borne by the operators and society.

3. *The EPA letter suggests that the "State reconsider the BACT decision for NO_X for the proposed KUA project" and requests "that the permit not be issued until we reach a consensus on the NO_X BACT analysis."*

The Department quickly set up a meeting and the presentation discussed above on March 4 with EPA, KUA, B&V, and invited General Electric and the Department of Energy to attend. EPA asked for a copy of the complete Site Certification Application and an estimate of cost impacts of installing SCR upon Busbar cost. KUA responded with the mentioned letter of March 24 and also provided the impacts on Busbar Costs. According to KUA (through B&V), the costs of electricity increase from $29.25 to 29.87 per megawatt-hour. Department representatives advised EPA's representatives at the meeting that a response would be appreciated within about one month.

The Department sent a letter on May 7 to EPA further explaining the benefits of the DLN strategy versus SCR in a letter regarding a Duke Energy project planned for Florida. The Department pointed out that total emissions from the Duke project will be substantially lower than emissions from the Southern Company projects. SCR encourages operation of the low emitting DLN units in such a manner (large duct burners and power augmentation) that they emit more carbon monoxide and volatile organic compounds (PSD pollutants) in addition to ammonia. The reason is that once an SCR unit is installed, NO_X emissions from the turbine section (before the catalyst) can be greatly increased with concomitant increases in CO and VOC. The latter two pollutants are normally well controlled by the DLN technology.

The Department prepared another letter (dated June 28) to the Fish and Wildlife Service detailing the situation for combined cycle projects in general. The Department arranged a teleconference on August 10 with EPA and representatives of the National Park Service and the Fish and Wildlife Service. Much of the discussion focused on the environmental effects of ammonia and its participation in fine particulate formation and regional haze. The Department stressed in the letter and the teleconference that the EPA and Park Service models specifically cite ammonia interaction with NO_X and SO_X as the contributor to PM and regional haze in its models. There were some doubts about the actual ammonia emissions from SCR controlled combustion turbine units. The Department agreed to search for such information.

The Department sent another letter on May 27 to EPA providing typical measured ammonia slip summaries. The data indicate slip rates of 7 ppmvd of ammonia with a standard deviation of 3 ppmvd. The Department indicated that typically NO_X emissions from units permitted to emit 9 ppmvd by DLN will actually be about 7.5 ppmvd. Therefore the Department concluded that the "typical reduction of NO_X by 4 ppmvd to 3.5 ppmvd will be accompanied by typical NH_3 slip of 7 ppmvd."

On October 27, EPA sent a letter to the Department indicating that it might object (through subsequent Title V permitting) to a similar permit already drafted for another project (Lake Worth LLC) in the State. That was the first clear indication that a BACT limit of 9 ppmvd by DLN is unacceptable to EPA Region IV.

The Department and EPA held a meeting on November 5 in Tallahassee to discuss the issue in general. KUA was one of the projects discussed. It was more urgent because the matter would be acted upon by the Siting Board on November 10. EPA expressed its appreciation of all of the concerns raised by the Department. They explained that Florida was the only state that did not require SCR on all combined cycle projects. They indicated that SCR is cost-effective on the basis that it is commonly used everywhere else.

The Department explained that it had concluded that SCR was not cost-effective for the project. EPA responded that the traditional cost-effectiveness method is no longer valid for these kinds of projects. They said that because SCR has been implemented throughout the country, cost-effectiveness is no longer an issue. Given that there is nothing unique about Florida, they do not agree that SCR can be rejected on the basis of cost-effectiveness calculations or that DLN can be allowed in lieu of SCR. They maintained their position that the other energy, environmental, and economic, and safety concerns were not sufficient to reject SCR or provide for a DLN alternative with higher NO_X emissions.

The Department pointed out that the State of Texas recently issued a generic draft BACT for combined cycle projects that is almost identical to the Department's draft BACT for the KUA project. Therefore Florida is not the only State that does not absolutely require SCR (or other add-on) control technology. As long as the applicant can meet single-digit NO_X values by DLN, Texas does not require add-on control equipment. If control equipment is installed, then it must meet lower NO_X values consistent with the capability of the equipment (e.g. 5 ppmvd).

The Department pointed out that it is only now being made aware that the traditional cost-effectiveness methodology was no longer valid for combined cycle projects. The Department advised that it had carefully evaluated the application, detailed its rationale and affixed professional engineer seals on its technical evaluation. The Department expressed its view that it can fully explain and support its conclusions. It was agreed by the Department and EPA that there is a professional disagreement on the matter.

The Department inquired about incorporation of the policy expressed by EPA on future projects. The KUA project had already reached a critical point in the approval process. Practically all of the written and administrative hearing record consists of documents detailing the Department and KUA's position on the BACT. It was agreed that the present meeting might best have been held a few months ago.

The Department advised that it had reduced the NO_X limit under the SCR option from 6 to 4.5 ppmvd in response to EPA's comments. Also the Department had reduced the NO_X limit under the SCR option to 3.5 ppmvd for the Lake Worth Project. Finally, the Department plans to impose a limit of about 3 ppmvd on another project planned in Florida where the applicant cannot achieve 9 ppmvd with DLN. The Department also is including a limit of 5 ppmvd on ammonia at least for projects permitted under Site Certification.

EPA advised that if the Department does not reverse its position on the KUA project, EPA will most likely petition the Environmental Appeals Board (EAB) to review the Department's decision. The Department asked EPA to provide the position in writing so that the matter can be discussed with KUA. This would provide KUA with a better understanding of the potential consequences of the Department maintaining its position regarding the matter. If KUA decides to exercise the option already in the permit to install SCR, then the DLN option can be removed ending EPA's objection.

EPA provided a letter on November 8 advising that it intends to appeal the KUA Permit if the Department does not require a NO_X emission rate of 3.5 ppmvd by SCR or other technology when firing natural gas. The situation was discussed with KUA in a subsequent meeting held on November 10. KUA elected to install SCR technology and meet a 3.5 ppmvd NO_X limit while firing natural gas as required by EPA. The reason is that an appeal would delay issuance of the final permit by roughly one year. KUA has contractual commitments that cannot be met since construction cannot commence until the permit is issued.

KUA requested relief on the ammonia limit so that no more catalyst is required under the 3.5 ppmvd NO_X SCR requirement than under the 4.5 ppmvd SCR option in the draft permit. The Department determined that the critical design parameter is the reduction of NO_X to 15 ppmvd with an ammonia slip of 5 ppmvd while firing fuel oil. That design is sufficient to achieve 3.5 ppmvd with a slip of 5 ppmvd while burning natural gas.

KUA requested the Department's cooperation in obtaining agreement from EPA that it will not file a petition with the EAB during the 30-day period described in 40CFR124.19 if KUA installs an SCR unit to achieve 3.5 ppmvd NO_X while firing natural gas. The Department received this assurance and conveyed it to KUA thus effectively resolving the comments that otherwise provide EPA with the basis for objecting during the 30-day period. This will allow KUA to begin construction upon receipt of the attached permit.

CONCLUSION

The initial application from KUA proposed a NO_X limit of 15 ppmvd, a VOC limit of 10 ppm, and a CO limit of 25 ppmvd under gas firing. By conducting a thorough evaluation and making a proper BACT determination, the proposed limits were reduced to 9 ppmvd of NO_X, 1.4 ppm of VOC, and 12 ppmvd of CO with proportional decreases in annual tonnage. The reductions in VOC are important as it is also a pre-cursor to ozone.

Projects permitted with SCR tend to have higher permitted CO and VOC emissions limits because turbines that cannot achieve low NO_X emissions by DLN do not achieve low VOC or CO emissions either. Addition of SCR to units that can otherwise achieve low NO_X without SCR, typically encourages operation of large duct burners and power augmentation equipment. Under these modes the small reduction in NO_X is accompanied by significant increases in VOC and CO as well as particulate matter and ammonia.

All impacts on ambient air quality from the KUA project under the DLN or SCR scenario are less than the significant impact levels that require detailed modeling. The project will not cause or contribute to a violation of any National Ambient Air Quality Standard or applicable increment.

The Department concludes that its BACT determination complies with all State and Federal regulations and fulfills the requirements and Intent of Part C of the Clean Air Act, Prevention of Significant Deterioration of Air Quality. The Department concurs that EPA's BACT requirement also constitutes BACT, although the uncertainty in NO_X measurements is on the order of the NO_X limitation.

The final action is to issue the permit as proposed but without the DLN option and with an SCR-based NO_X limit of 3.5 ppmvd while firing gas.

FLORIDA

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

PERMITTEE:

Kissimmee Utility Authority (KUA)
1701 West Carroll Street
Kissimmee, Florida 34741-6804

File No.	PSD-FL-254 (PA98-38)
FID No.	0970043
SIC No.	4911
Expires:	December 31, 2002

Authorized Representative:

A.K. Sharma, Director of Power Supply

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 167 megawatt (MW) gas-fired, stationary combustion turbine-electrical generator; a supplementally-fired heat recovery steam generator (HRSG); a nominal 80-90 MW steam electrical generator; a 1.0 million gallon storage tank for back-up distillate fuel oil; a selective catalytic reduction unit and ancillary equipment; ammonia storage; a 130-foot stack; and a 100-foot bypass stack for simple cycle operation. The unit will achieve approximately 250 megawatt in combined cycle operation at referenced conditions. The unit is designated as Unit 3 and will be located at the Cane Island Power Park, 6075 Old Tampa Highway, near Intercession City, Osceola County. UTM coordinates are: Zone 17; 447.72 km E; 3127.68 km N.

STATEMENT OF BASIS:

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR52.21. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

The attached Appendix is made a part of this permit:

Appendix GC — Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

The existing Kissimmee Utility Authority (KUA) Cane Island Power Park consists of a nominal 40 MW simple cycle combustion turbine designated as Unit 1 and a nominal 120 MW combined cycle combustion turbine-electrical generator with a heat recovery steam generator (HRSG) and a steam electrical generator designated as Unit 2.

The proposed KUA Cane Island Power Park Unit 3 is a nominal 250 MW combined cycle plant. It will include: a nominal 167 MW stationary gas combustion turbine-electrical generator burning natural gas with fuel oil as backup; a supplementally gas-fired heat recovery steam generator to raise sufficient steam to achieve 250 MW in combined cycle operation; an 80-90 MW steam electric generator, a 44 mmBtu/hr heat input duct burner; a selective catalytic reduction unit and ancillary equipment; ammonia storage; a 130-foot stack; and a 100-foot bypass stack for simple cycle operation. New major support facilities for Unit 3 include a cooling tower, water and wastewater facilities, water storage tanks, storm water detention pond, 230 KV transmission line, and a 1.0 million gallon storage tank for back-up distillate fuel oil.

Emissions from Cane Island Power Park Unit 3 will be controlled by Dry Low NO_X (DLN) combustors or wet injection under simple cycle operation. Emissions will be controlled by DLN or wet injection and selective catalytic reduction (SCR) when operating in combined cycle mode. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
003	Power Generation	One nominal 167 Megawatt Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	1.0 Million Gallon Fuel Oil Storage Tank
005	Steam Generation	One 44 mmBtu/hr Duct Burner in a Supplementally Fired Heat Recovery Steam Generator (and 80-90 MW Steam Electrical Turbine)
006	Water Cooling	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).

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-254

SECTION I - FACILITY INFORMATION

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). 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}, 100 TPY of CO and 40 TPY of VOCs. 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 is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is greater than 75 MW. [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

- 11/23/99 PSD Permit Issued
- 11/22/99 Site Certification Issued
- 01/09/99 Notice of Intent to Issue PSD Permit published in The Orlando Sentinel
- 01/07/99 Distributed Intent to Issue Permit
- 08/05/98 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.

- Application received on August 5, 1998
- Department/BAR letters to KUA dated August 17, and September 23, 1998
- Comments from the Fish and Wildlife Service dated September 11, 1998
- KUA letters (through Black & Veatch) dated November 6 and November 30, 1998 and January 6, February 3, February 12, March 10, and March 24, 1999.
- Department's Intent to Issue and Public Notice Package dated January 8, 1999.
- Department's revised Draft Permit and BACT determination dated March 25, 1999.
- Letters from EPA Region IV dated February 2, February 10, and November 8, 1999.
- Black & Veatch and GE Presentations to Department and EPA Region IV on March 4, 1999.
- Site Certification for the KUA Cane Island Facility approved November 22, 1999.
- 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 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767 and phone number 407/894-7555.
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 conjunction with extension of the 18 month periods to commence or continue construction, or extension of the December 31, 2002 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [40 CFR 52.21(j)(4)]
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 (Rule 62-4.080, F.A.C.).

9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]
10. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Central District Office. [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 Central District Office by March 1st of each year.
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) (1998 version), shall be submitted to the DEP's Central District Office.

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 Unit 003. Direct Power Generation, consisting of a nominal 167 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).
5. ARMS Emission Unit 004. Fuel Storage, consisting of a 1.0 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C.
6. ARMS Emission Unit 005. Steam Power Generation, consisting of a supplementally-fired heat recovery steam generator equipped with a natural gas fired 44 mmBTU/hr duct burner (HHV) and 80-90 MW steam electrical generator shall comply with all applicable provisions of 40CFR60, Subpart Dc, Standards of Performance for Small Industrial Commercial-Institutional Steam Generating Units Which Construction is Commenced After September June 9, 1989, adopted by reference in Rule 62-204.800(7), F.A.C.
7. ARMS Emission Unit 006. Cooling Tower, is an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because Chromium-based chemical treatment is not used.
8. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District Office.

GENERAL OPERATION REQUIREMENTS

9. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Combustion Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to this Unit at ambient conditions of 19°F temperature, 55% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,696 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,910 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

11. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 44 mmBtu/hour (HHV). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

12. 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.

13. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Central District office 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.]

14. 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.]

15. 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.]

16. Maximum allowable hours of operation for the 250 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. Fuel oil firing of the combustion turbine is permitted for a maximum of 720 hours per year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

17. Simple Cycle Operation The plant may be operated in simple cycle mode. Different limits apply depending upon whether simple cycle operation is of an intermittent nature, such as: caused by maintenance of equipment following the combustion turbine; temporary electrical demand fluctuations; a decision to not install the heat recovery steam generator; or long term electrical demand situations.

CONTROL TECHNOLOGY

18. Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine to comply with the simple cycle NO_X emissions limits listed in Specific Condition 24. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

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

20. The permittee shall install selective catalytic reduction system to comply with the combined cycle NO_X limit listed in Specific Condition 24.

21. 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. 24 through 28. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

22. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize simple cycle NO_X emissions and CO emissions. [Rule 62-4.070, and 62-210.650 F.A.C.]

23. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions.

EMISSION LIMITS AND STANDARDS

24. Nitrogen Oxides (NO_X) Emissions:

A. Combined Cycle Operation

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) and the duct burner on or off, shall not exceed 3.5 (15) ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). Emissions of NO_X calculated as NO_2 in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 26 (108) pounds per hour (lb/hr) with the duct burner on or off to be demonstrated by initial stack test. [Applicant Request on November 9, 1999]

- The concentration of ammonia in the exhaust gas from each combustion turbine shall not exceed 5 ppmvd @15% O_2. The compliance procedures are described in Specific Condition 52. [Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

B. *Intermittent Simple Cycle Operation*

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) shall not exceed 12 (42) ppmvd at 15% O_2 (24-hr block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 86 (310) pounds per hour (lb/hr). [Rules 62-212.400, F.A.C.]
- Notwithstanding the applicable NO_X limit during simple cycle operation, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower. Any tuning of the combustors for Dry Low NO_X operation while firing gas shall result in initial subsequent NO_X concentrations of 9 ppmvd @15% O_2 or lower. [Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

C. *Continuous Simple Cycle Operation*

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) shall not exceed 9 (42) ppmvd at 15% O_2 (24-hr block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 65 (310) pounds per hour (lb/hr). [Rules 62-212.400, F.A.C.]
- Notwithstanding the applicable NO_X limit during simple cycle operation, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower. Any tuning of the combustors for Dry Low NO_X operation while firing gas shall result in initial subsequent NO_X concentrations of 9 ppmvd @15% O_2 or lower. [Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

25. <u>Carbon Monoxide (CO) Emissions</u>: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas (fuel oil) shall exceed neither 12 (20) ppm nor 43 (71) lb/hr with the duct burner off and neither 20 (30) ppm nor 71 (108) lb/hr with the duct burner on to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

26. <u>Volatile Organic Compounds (VOC) Emissions</u>: Emissions of VOC in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas (fuel oil) shall exceed neither 1.4 (10) ppm nor 3 (21.4) lb/hr with the duct burner off and neither 4 (10) ppm nor 8.5 (21.4)

lb/hr with the duct burner on to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]

27. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for 720 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 48 and 49 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. Emissions of SO_2 shall not exceed 38.1 tons per year. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C. to avoid PSD Review]

28. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine operating with or without the duct burner and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

29. 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 both "cold start-up" to or shutdowns from combined cycle plant operation. During start-up to simple cycle operation, up to one hour of excess emissions are allowed. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

30. 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 24-hr average for NO_X.

31. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office 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, 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. 24. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

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

33. Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 32. Initial tests shall also be conducted after any substantial modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as installation of SCR or change of combustors. 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.

   - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Test must be conducted with the duct burner on and with the duct burner off.
   - EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
   - EPA Method 26A (modified) for ammonia sample collection
   - EPA Draft Method 206 for ion chromatographic analysis for ammonia.

34. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system on a 3-hr average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hr period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 3-hr period. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. These excess emissions periods shall be reported as required in Condition 31. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

35. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, 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).

36. Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75. Alternatively to annual testing in a given year, periodic tuning data may be provided to demonstrate compliance in the year the tuning is conducted.

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

38. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. 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.

39. Test Notification: The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

40. Special Compliance Tests: The DEP 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.

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

42. Records: All measurements, records, and other data required to be maintained by KUA 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 representatives upon request.

43. 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.

MONITORING REQUIREMENTS

44. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen from these units. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the permitted limits, listed in Specific Condition No. 24, shall be reported to the DEP Central District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day). [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

45. CEMS for reporting excess emissions: The NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Upon request from DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [EPA Approval dated February10, 1999]

46. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X on this Unit shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [EPA Approval dated February10, 1999]

47. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

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

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

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

50. Determination of Process Variables:

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

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

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

- An initial stack emission test for nitrogen oxides and ammonia from the CGT/HRGS pair shall be conducted: 1) for natural gas firing and 2) for distillate fuel oil firing. The ammonia injection rate necessary to comply with the NO_X standard shall be established during the initial performance tests.

- The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods. During turbine start-up, permittee shall begin use of SCR (i.e., commence ammonia injection) within two (2) hours of the initial turbine firing or when the temperature of the catalyst bed reaches a suitable predetermined temperature level, whichever occurs first. During turbine shutdown, permittee shall discontinue use of the SCR (i.e., discontinue ammonia injection) when the catalyst bed temperature drops below the predetermined temperature levels, but no more than one hour prior to the time at which the fuel feed to the turbine is discontinued. Suitable temperature for activation and deactivation of the SCR shall be established during performance testing. The permittee shall, whenever possible, operate the facility in a manner so as to optimize the effectiveness of the SCR unit while minimizing ammonia slip to below the emission limit.
- The permittee shall install and operate an ammonia flow meter to measured and record the ammonia injection rate to the SCR system of the CGT/HRSG set. It shall be maintained and calibrated according to the manufacture's specifications. During the stack test, the permittee at each load condition shall determine the minimum ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at greater or equal to 100% of the ammonia injection rate determined during the stack test.

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 extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Cane Island Power Park Unit 3
Kissimmee Utility Authority
PSD-FL-254 and PA98-38
Intercession City, Osceola County, Florida

BACKGROUND

The applicant, Kissimmee Utility Authority (KUA), proposes to install a nominal 250 megawatt (MW) (net) combined cycle combustion turbine at the existing Cane Island Power Park, located at 6075 Old Tampa Highway, near Intercession City, Osceola County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), 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 primary unit to be installed is a nominal 167 MW, General Electric PG7241FA (7FA) combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an 80-90 MW heat recovery steam generator (HRSG) with a steam turbine-electrical generator. Duct burners will be installed in the HRSG for supplemental firing to compensate for reduced combustion turbine capacity at high ambient temperature. The project also includes a new 1 million gallon storage tank for backup No. 2 fuel oil, cooling tower, 130 foot stack for combined cycle operation, and a 100 foot bypass stack for simple cycle operation. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated January 8, 1999, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on August 5, 1998 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch. A revision which reduced the proposed emission limits was received on November 6 through a Response to Statement of Sufficiency. A draft BACT was issued by the Department on January 7, 1999. It was revised on March 25 as a result of comments received by the Department. The revised version was introduced by KUA into the record of the Administrative Hearing held on June 1 pursuant to the Site Certification requirements of the Florida Power Plant Siting Acton. The draft BACT included therein constitutes KUA's most recent BACT proposal. The proposal is summarized in the table below.

POLLUTANT	CONTROL TECHNOLOGY	BACT PROPOSAL
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip if SCR is used
VOC	As Above	1.4 ppm (Gas, CT on, DB off) 4 ppm (Gas, CT and DB on)) 10 ppm for F.O.
CO	As Above	12 ppmvd (Gas, CT on, DB off) 20 ppmvd (Gas, CT and DB on) 30 ppmvd for F.O.
NO_X (CT on, DB off)	DLN, or DLN & SCR for gas WI or SCR for fuel oil 720 Hours on fuel oil with DB On or Off	9 ppmvd (DLN) or 4.5 ppmvd (SCR) for gas 42 ppmvd (WI) or 15 ppmvd (SCR) for fuel oil 12/42 ppmvd (gas/oil) Intermittent Simple Cycle
NO_X (CT and DB on)	DLN & Low NO_X, or DLN & SCR for gas WI & Low NO_X, or SCR for fuel oil Duct burner only fires natural gas	9.4 ppmvd (DLN) or 4.5 ppmvd (SCR) for gas 42 ppmvd (WI) or 15 ppmvd (SCR) for fuel oil DB limited to 0.4 lb/MW-hr

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, 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). Subpart GG was adopted by the Department 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 the KUA is consistent with the NSPS which allows NO_X emissions in the range of 110 ppmvd for the high efficiency unit to be purchased by the Kissimmee Utility Authority. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

The duct burner required for supplementary gas-firing of the HRSG at high ambient temperatures is subject to 40 CFR 60, Subpart Dc, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. There are no NSPS-based emission limits for these small units when firing natural gas.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent BACT determinations by States in the South 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 or G Class Frame units. The greatest activity in combined cycle installations appears to be in Texas, Florida, and Alabama. The KUA draft 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
Alabama Power Barry	800	4.8* - NG Permit Limit is 0.018 lb/mmBtu	DLN & SCR	3x170 MW GE 7FA CTs 11/98 Cannot meet 9 ppmvd w/o SCR Large DB and Pwr Augmentation
Alabama Power Theo	210	4.8* – NG Proposed Limit is 0.018 lb/mmBtu	DLN & SCR	4x170 MW GE 7FA CTs 11/98 Cannot meet 9 ppmvd w/o SCR Large DB and Pwr Augmentation
KUA Cane Island 3	250	9/4.5 - NG (CT) 9.4/4.5 - (CT&DB) 42/15 - FO	DLN/SCR DLN/SCR WI/SCR	170 MW GE 7FA. 11/99 Increase allowed for DB. If SCR, **ammonia** slip = 5 ppmvd
Lake Worth LLC, FL	250	9/3.5 - NG (CT) 9.4/3.5 - (CT&DB) 42 - FO	DLN/SCR DLN/SCR WI	170 MW GE 7FA. 11/99 Increase allowed for DB. Project repowers one+ units
Lakeland, FL	350	9/7.5 – NG 42/15 – FO	DLN/SCR WI/SCR	250 MW WH 501G 7/98 Initially 250 MW simple cycle and 25 ppmvd NO_X limit on gas
Santa Rosa, FL	241	9 - NG (CT) 9.8/6 (CT&DB)	DLN DLN/SCR	170 MW GE 7FA CT. 12/98 6 ppmvd if SCR or SNCR
Tallahassee, FL	260	12 - NG 42 - No. 2 FO	DLN	160 MW GE 7FA CT. 7/98 DLN guarantee is 9 ppmvd
LSP Batesville, MI	~800	9 - NG 42 - No. 2 FO	DLN & SCR WI	3x185 MW WH 501F CTs. 11/97 Revised 7/98. Large DB Cannot meet 9 ppmvd w/o SCR
Miss Power Daniel	1000	4.8* – NG Permit Limit is 0.018 lb/mmBtu	DLN & SCR	4x170 MW GE 7FA CTs 11/98 Cannot meet 9 ppmvd w/o SCR Large DB and Pwr Augmentation
Panda Guadalupe TX	1000	9 - NG	DLN	4x170 MW GE 7FA CTs 2/99
Hays San Marco, TX	1080	5 - NG	SCR	4x175 ABB GT24 CTs. 6/99 Cannot meet 9 ppmvd w/o SCR
Duke Hidalgo, TX	520	12 - NG	DLN	2x170 MW GE 7FA CTs 12/98
Tenaska Rusk, TX	888	9 - NG	DLN	3x164 MW GE 7FA CT. 5/99
Sabine River, TX	440	6 - NG	DLN & SCR	2 x170 MW GE 7FA CTs 6/99
GTP/Calpine, TX	500	5 – NG	SCR	2x183 MW WH501F CTs 9/99 Cannot meet 9 ppmvd w/o SCR

DB = Duct Burner DLN = Dry Low NO_X Combustion GE = General Electric
NG = Natural Gas SCR = Selective Catalytic Reduction WH = Westinghouse
FO = Fuel Oil WI = Water or Steam Injection ABB = Asea Brown Bovari

- Reportedly revised in mid-1999 to 0.013 lb/mmBtu which equals 3.5 ppmvd

There are more than 20 applications pending for similar projects in Texas with similar BACT proposals as indicated above. There are numerous applications for similar projects throughout the Southeast including Florida, all of which include BACT proposals within the range of the determinations given above.

TABLE 2

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

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppm (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)	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
Alabama Power Barry	~15 – NG(CT) ~25 – NG(DB & CT)	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion
Alabama Power Theo	~36 – CT & DB	~12.5 CT & DB		Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Lake Worth LLC, FL	9 - NG (CT) 15 – NG (CT & DB) 20 - F.O. (3-hr)	1.4 - NG (CT) 1.8 - NG (CT & DB) 3.5 – F.O.	10% Opacity	Clean Fuels Good Combustion
Lakeland	25 – NG or 10 by Ox Cat 75 – FO	4 – NG 10 – FO	10%	Clean Fuels Good Combustion
Santa Rosa, FL	9 - NG (CT) 24 - NG (CT&DB)	1.4 - NG (CT) 8 - NG (CT&DB)	10% Opacity	Clean Fuels Good Combustion
Tallahassee, FL	25 – NG 90 – FO			Clean Fuels Good Combustion
LSP Batesville, MI	30 at > 75% load - NG 36 at > 75% load - FO	9 at > 75% load – NG 15 at > 75% load - FO	40% Opacity	Clean Fuels Good Combustion
Miss Power Daniel	~15 - NG(CT) ~25 – NG(DB & CT	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion
Panda Guadalupe TX	15 - NG			Clean Fuels Good Combustion
Hays San Marco, TX	9 - NG			Clean Fuels Good Combustion
Duke Hidalgo, TX	20 - NG			Clean Fuels Good Combustion
Tenaska Rusk, TX	25 - NG			Clean Fuels Good Combustion
Sabine River, TX	15 - NG			Clean Fuels Good Combustion
GTP/Calpine, TX	10 or 25			Clean Fuels Good Combustion

The following table is derived from the information given above for projects incorporating duct burners within supplementally-fired heat recovery steam generators. There are a number of projects from the lists above for which the Department did not obtain the details regarding the duct burners. The main focus was on NO_X emissions.

TABLE 3

RECENT BACT LIMITS FOR NITROGEN OXIDES FROM LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS WITH DUCT BURNERS

Project Location	Duct Burner Rated Heat Input (mmBtu/hr)	NO_X Limit (lb/mmBtu or ppmvd)	Technology	Comments
Mobile Power, FL	585	3.5	SCR	Combined CT & DB
Alabama Power Barry	159	4.8	SCR	Combined CT & DB Possibly revised to 3.5
Alabama Power Theo		4.8	SCR	Combined CT & DB Possibly revised to 3.5
KUA Cane Is, FL	44	9.4/4.5 - (CT&DB) 42/15 - FO	DLN or DLN & SCR DLN or DLN & SCR WI or WI & SCR	Gas-fired Duct Burner Low NO_X Burners on DB Max 0.4 lb/MW-hr on DB
Santa Rosa, FL	585	9.8/6 (CT&DB)	DLN or DLN & SCR	Gas-fired Duct Burner Low NO_X Burners on DB Max 0.4 lb/MW-hr on DB
Miss Power Daniel	159	4.8	SCR	Combined CT & DB Possibly revised to 3.5
Saranac Energy, NY	553	0.08 lb/mmBtu	SCR	2 GE 7EA CTs with DBs Permit issued 1992
Bermuda HEL, VA	197	9	Steam Injection, SCR	1175 mmBtu/hr CT (1992)
Bear Island Paper, VA	129	9	SCR	474 mmBtu/hr CT (1992)
Pilgrim Energy, NY	214	4.5 (CT) 0.012 lb/mmBtu (DB)	Steam Injection, SCR Low NO_X Burner, SCR	2 WH 501D5 CTs 2 Duct Burners
Selkirk Cogen, NY	206	9 (CT) 0.018 lb/mmBtu (DB)	Low NO_X Burner, SCR	1173 mmBtu/hr CT
Grays Ferry, PA	366	9 (CT) 0.09 lb/mmBtu (DB)	DLN Low NO_X Burner	WH 501D5A CT with DB DLN Failed, SCR Required

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:

- Comments from the National Park Service dated, September 11 1998
- Master Overview for Alabama Power Plant Barry Project received in 1998
- Master Overview for Mississippi Power Plant Daniel Project received in 1998
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island Unit 3
- Presentations by Black & Veatch and General Electric at EPA Region IV on March 4, 1999
- Letter from Black & Veatch to EPA Region IV dated March 10, 1999
- Letter from Black & Veatch to the Department and EPA Region IV dated March 24, 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 Plant Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

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

Nitrogen Oxides Formation

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

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

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas its use is limited to 720 hours per year.

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

NO_X Control Techniques

Wet Injection

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

Combustion Controls

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

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

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

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

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

The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X and 9 ppmvd of CO. Emissions characteristics by wet injection NO_X control while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed (while firing natural gas) DLN-2.6 combustor to be installed at the KUA project are shown in Figure 4.

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

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

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

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

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from large gas turbines, such as the GE 7FA line. Specialized dual fuel DLN burners were installed in a project in Israel[1], but their performance on fuel oil is not known to the Department.

Figure 6 is an example of an in-line duct burner arrangement and an individual burner. 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 is only 44 mmBtu/hr compared with the turbine that can accommodate a heat input greater than 1600 mmBtu/hr (LHV). The duct burner will be of a Low NO_X design and will be used to compensate for loss of capacity at high ambient temperatures.

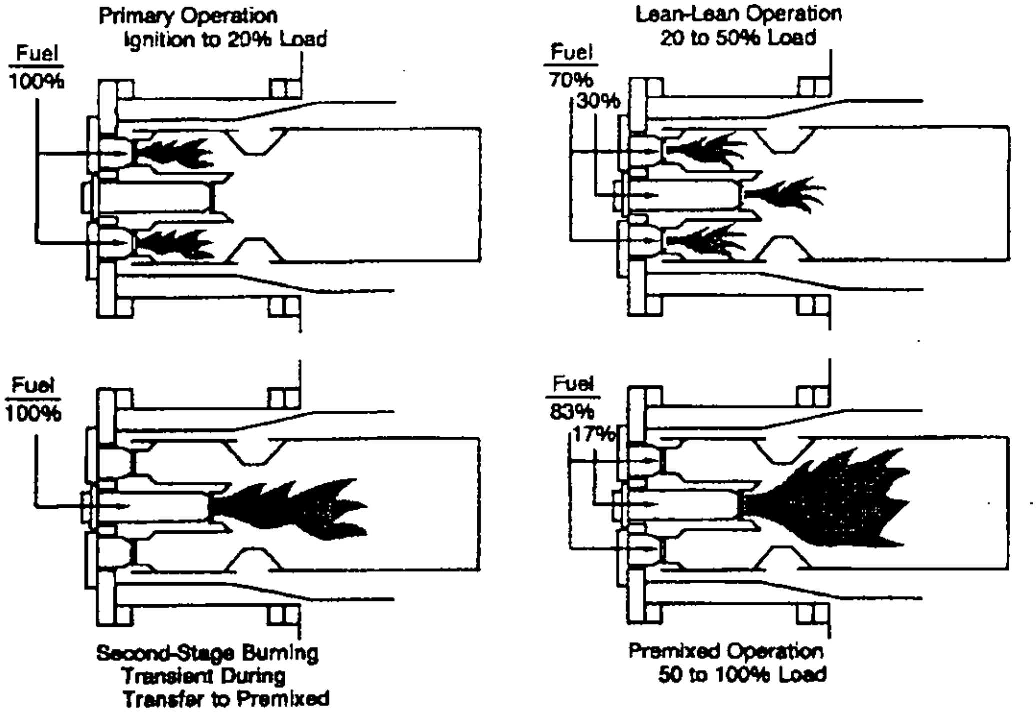
Selective Catalytic Combustion

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

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

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) 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. The reasons are similar to those for the FPC Hines Power Block I.

Figure 7 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 8 is a photograph of FPC Hines Energy Complex.



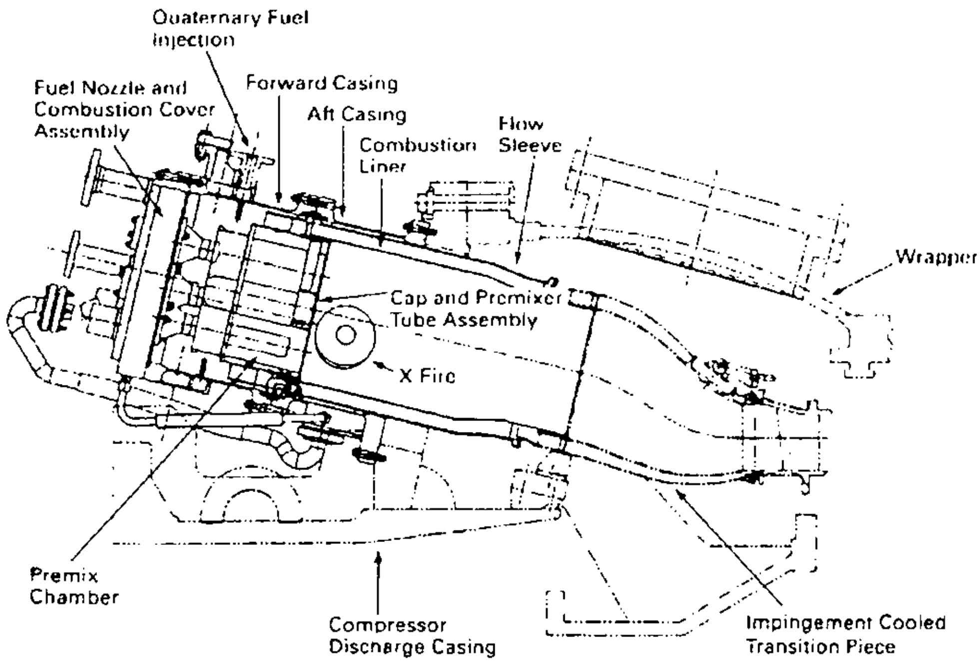


Figure 1 – Dry Low NO_X Operating Modes – DLN-1
Cross Section of GE DLN-2

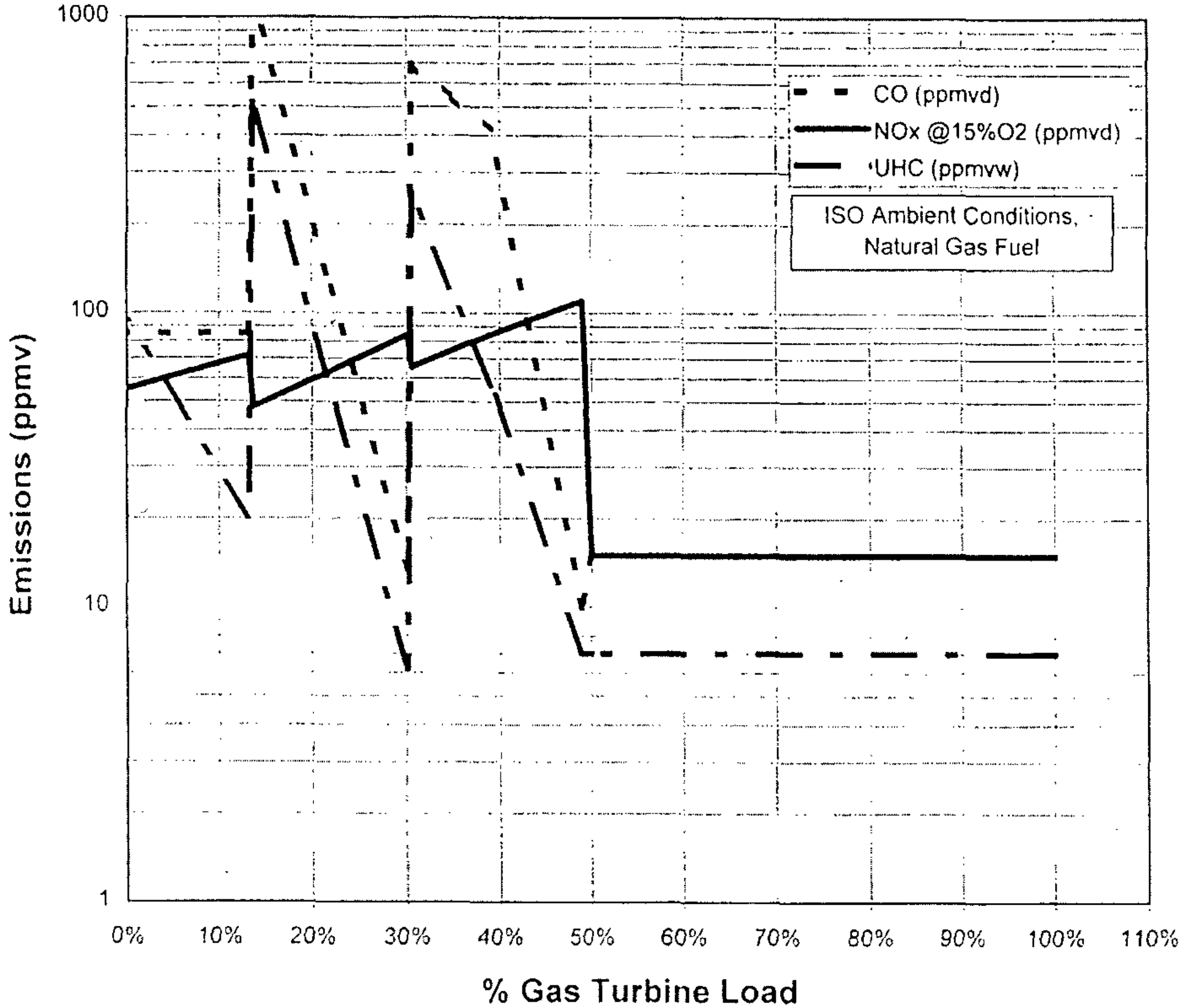


Figure 2 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

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

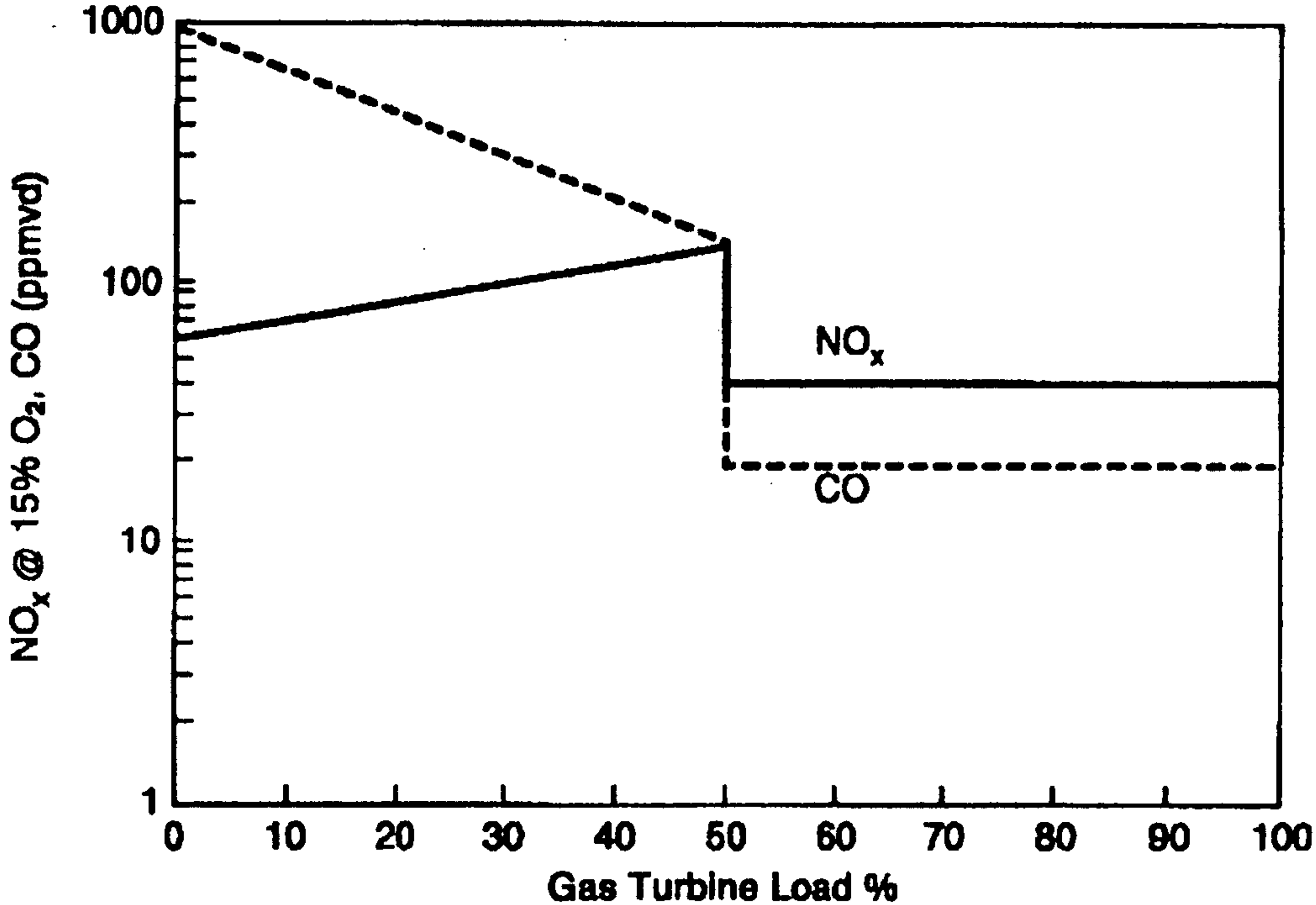


Figure 3 – Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

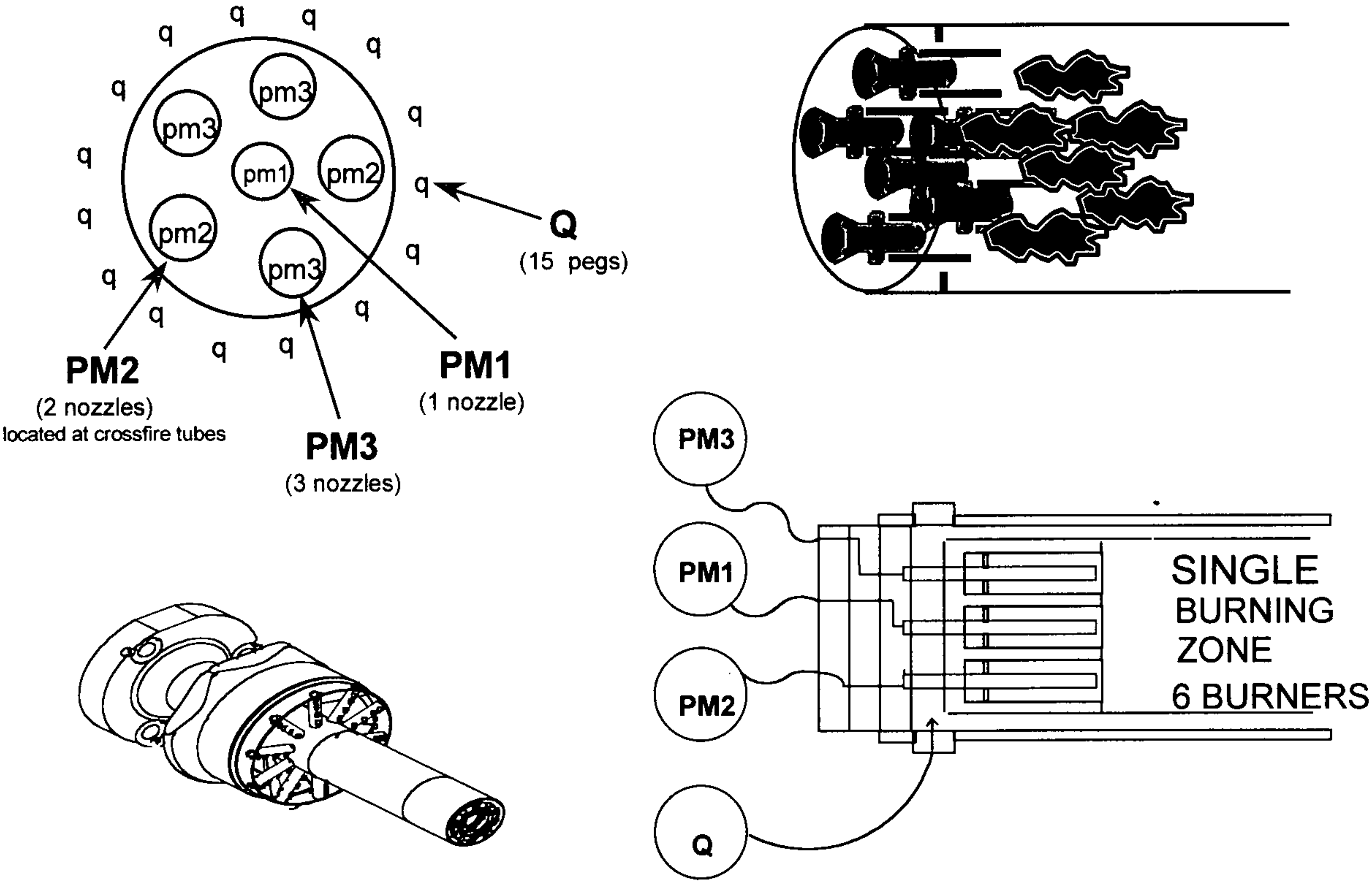


Figure 4 - DLN2.6 Fuel Nozzle Arrangement

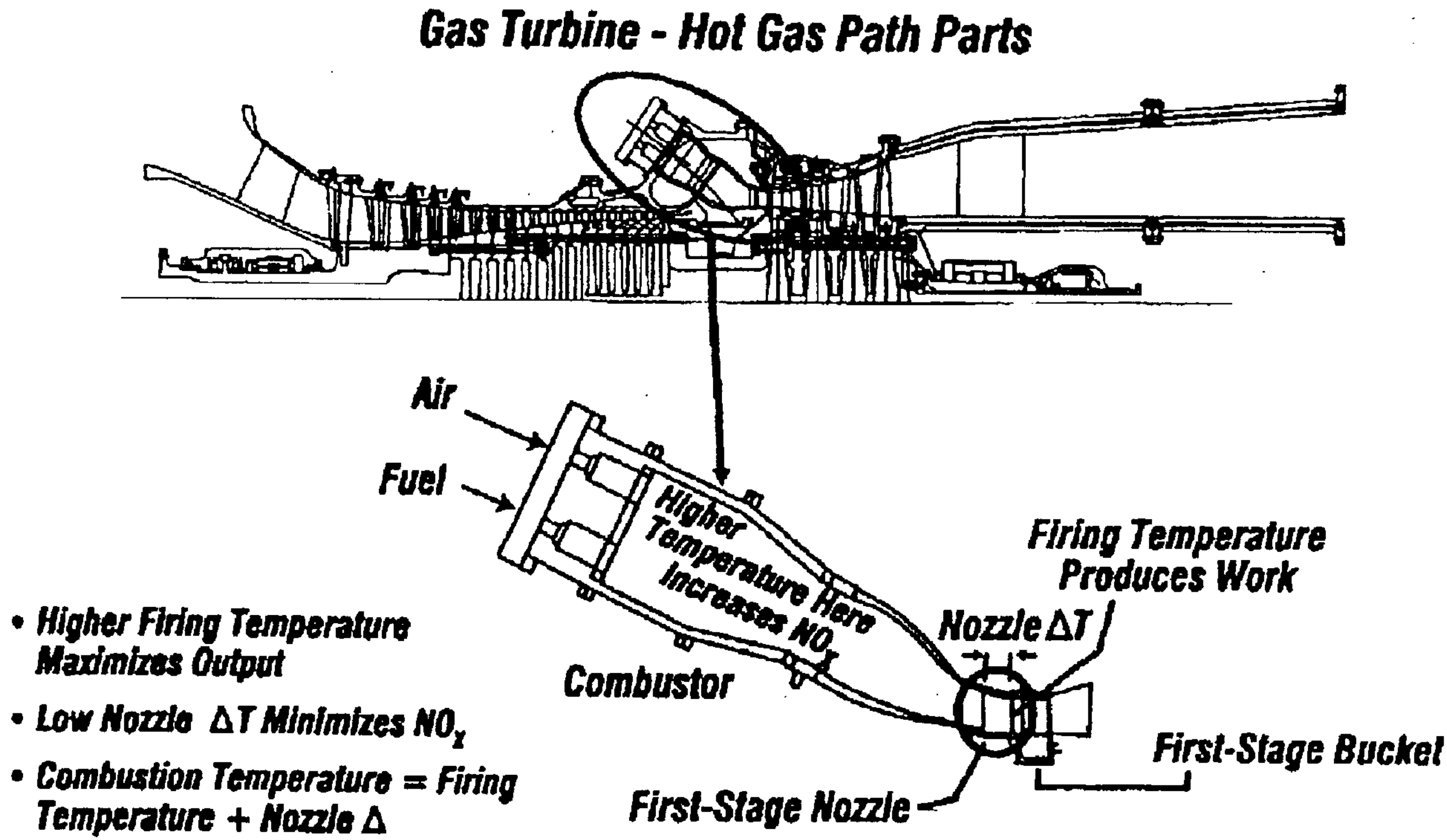
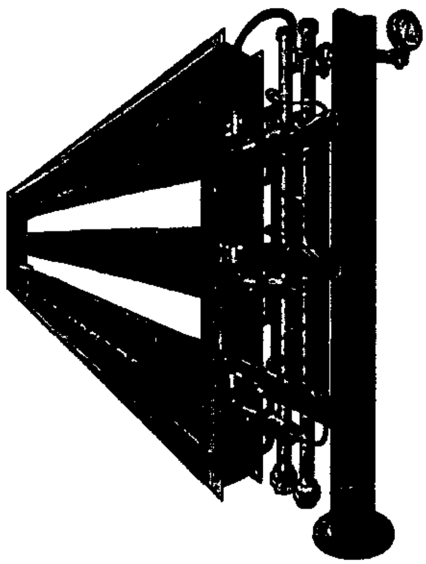
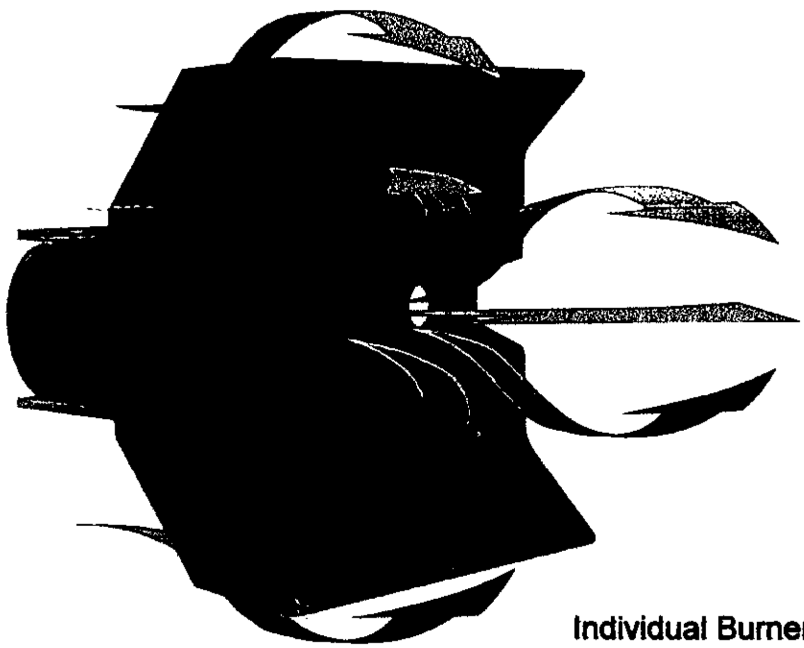


Figure 5 – Relation Between Flame Temperature and Firing Temperature

Burner Arrangment





Individual Burner

Figure 6 - Coen In-line Duct Burner and Arrangement

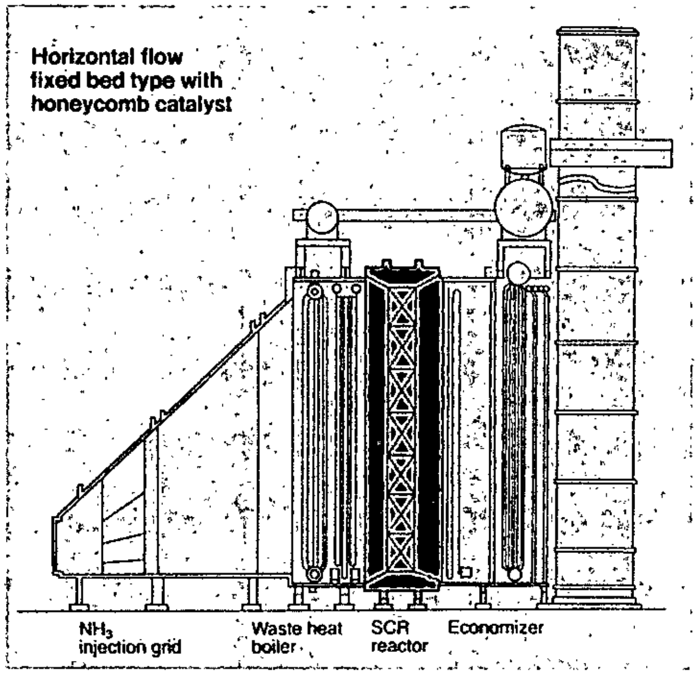


Figure 7 – SCR System within HRSG

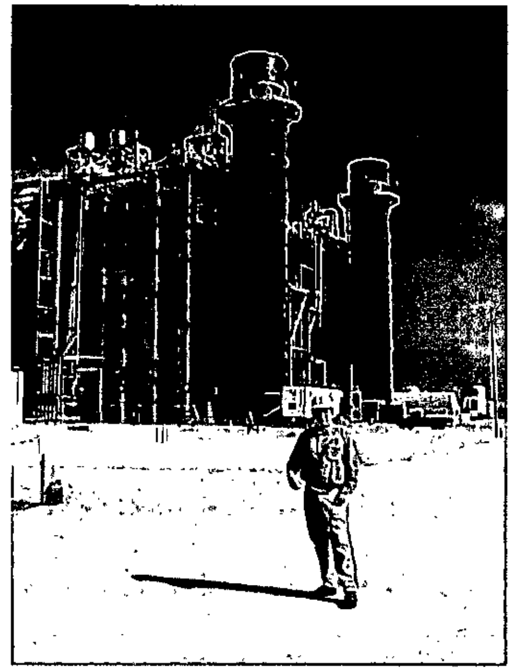


Figure 8 – FPC Hines Power Block I

The external lines to the ammonia injection grid are easily visible in Figure 8. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

Excessive ammonia use tends to increase emissions of CO, 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 as low as 3.5 ppmvd NO_X have been specified using SCR for at least one F Class project (with large in-line duct burners) in the Southeast.

In a project such as KUA Cane Island, the DLN system will reduce potential emissions from about 200 ppmvd to 9 ppmvd while firing gas. Such a DLN system is a sophisticated combustion system that optimizes efficiency and emissions. An SCR system at KUA would further reduce emissions to about 4.5 ppmvd at a substantial cost and obviously with add-on control equipment that does nothing to enhance efficiency. It increases PM formation and substitutes another pollutant (ammonia) while bringing NO_X emissions to levels equal to the uncertainty in the measurement method.

Selective Non-Catalytic Combustion

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

The acceptable temperature for the removal reactions is between 1400 and 2000 °F. A supplementally-fired HRSG is defined as a HRSG fired to an average temperature not exceeding about 1800 °F. The 44 mmBtu/hr duct burner described by KUA will not achieve these temperatures close to this value. Although it is one of the approved options for the Santa Rosa Energy Center, which incorporates a 585 mmBtu/hr duct burner, SNCR does not appear to be feasible for KUA's project.

Emerging Technologies: SCONOX™ and XONON™

$SCONO_X$™ 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.[2] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at PG&E's La Paloma Plant near Bakersfield.[3] The overall project includes several more 250 MW blocks with SCR for control.[4] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system

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

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx™ process was deemed as technically feasible for maintaining NO_X emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998).

XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as $SCONO_X$™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

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

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

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

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

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 720 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air.

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 Sutter Calpine 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.[5]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. KUA proposes to meet a limit of 10 ppmvd while firing natural gas with the small duct burner off. The higher values of 20 and 30 while firing gas or fuel oil with the duct burner operating are still within the range. The present proposal is a big improvement compared to the original proposal of 25 ppmvd when firing gas and 90 ppmvd when firing oil.

According to recent test data reviewed by the Department, actual CO emissions from large F Class frame units are less than 5 ppmvd, even when firing fuel oil. The Department has not reviewed an extensive body of actual data, but has reasonable assurance that the GE PG7241FA unit selected by KUA will achieve values well below those proposed without requiring installation of an oxidation catalyst.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by KUA for this project are 1.4 ppm for gas with the duct burner off or 4 ppm with the duct burner on. The limit proposed by KUA is 10 ppm for oil firing whether the duct burner is on or off. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[6]

Based on the chosen equipment, the Department believes VOC emissions will actually be well within the values proposed by KUA.

BACKGROUND ON SELECTED GAS TURBINE

KUA plans to the purchase a 167 MW (nominal) General Electric 7FA combined cycle gas turbine with a supplementary-fired heat recovery steam generator (HRSG) equipped with a small duct burner and a steam turbine-electrical generator to produce an additional 80-90 of electrical power. The 44 mmBtu/hr duct burner will incorporate a low NO_X design.

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

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[8] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppmvd of CO, and 0-0.17 ppmvd of VOC.[9] The City of Tallahassee received a permit in 1998 to install a GE PG7231FA combustion turbine at its Purdom Plant.[10] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[11]

FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for fourteen GE 7241FA turbines to be installed at the Fort Myers and Sanford Repowering Projects.[12, 13] The Santa Rosa Energy Center and the Lake Worth LLC Project in Florida received permits with a 9 ppmvd NO_X BACT limit for GE 7241FA turbines with DLN-2.6 burners.[14] Further examples are given in Table 1 above.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combustion turbines in Florida. When required by BACT determinations of most states, General Electric incorporates SCR in combined cycle projects.[15] In its recent permits, Florida has included separate and lower limits in the event that GE's DLN technology does not achieve 9 ppmvd or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[16] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[17] Unit 2 is equipped with DLN-1 combustors. According to GE, similar performance is expected soon on the 7FA line such as the one that will be installed for the KUA Project. Performance guarantees less than 9 ppmvd can be expected for DLN-2.6 combustors on units delivered in a couple of years.[18]

The 9 ppmvd NO_X limit on natural gas during baseload requested by KUA is typical compared with recent BACT determinations for F Class units, such as those previously listed. The 4.5 ppmvd value for the SCR option is in-line with the recent projects listed in Table 1 that incorporate the SCR option. Although at least one of those projects has a limit of 3.5 ppmvd, it is noted that none of the projects on the list has an ammonia slip limit. The KUA ammonia limit of 5 ppmvd is lower than the typical slip guarantee value.

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. The Mark V also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values.[19]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the KUA project assuming full load. Values for NO_X are corrected to 15% O_2. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 24 through 29.

POLLUTANT	CONTROL TECHNOLOGY	BACT DETERMINATION
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip if SCR is used
VOC	As Above	1.4 ppm (Gas, CT on, DB off) 4 ppm (Gas, CT and DB on)) 10 ppm for F.O.
CO	As Above	12 ppmvd (Gas, CT on, DB off) 20 ppmvd (Gas, CT and DB on) 30 ppmvd for F.O.
NO_X (CT on, DB off)	DLN, or DLN & SCR for gas WI or SCR for fuel oil 720 Hours on fuel oil with DB On or Off	9 ppmvd (DLN) or 4.5 ppmvd (SCR) for gas 42 ppmvd (WI) or 15 ppmvd (SCR) for fuel oil 12/42 ppmvd (gas/oil) Intermittent Simple Cycle
NO_X (CT and DB on)	DLN & Low NO_X, or DLN & SCR for gas WI & Low NO_X, or SCR for fuel oil Duct burner only fires natural gas	9.4 ppmvd (DLN) or 4.5 ppmvd (SCR) for gas 42 ppmvd (WI) or 15 ppmvd (SCR) for fuel oil DB limited to 0.4 lb/MW-hr

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 $SCONO_X$. There are permitted projects for large turbines requiring $SCONO_X$ or SCR.
- The "Top" technology in a top/down analysis will achieve 2 ppmvd.
- The Department has reviewed CEMS data from Fort St. Vrain, CO indicating that a similar unit with DLN-2.6 combustors consistently achieved less than 9 ppmvd NO_X in 1997 (obviously with no ammonia slip).[20]
- DLN is a pollution prevention technology. It controls NO_X by not allowing it to form and does not result in emissions of another pollutant (ammonia). The procedures given in the Top/Down methodology allow for cost-effectiveness of further control to be calculated using the pollution prevention technology as the baseline value.
- Starting with a baseline of 9 ppmvd, KUA estimated the cost of SCR to reduce emissions from 9 to 3.5 ppmvd at $5452 per ton assuming 10 ppmvd ammonia slip. KUA estimated cost-effectiveness at $16,056 per ton when the collateral emissions of PM, CO, and ammonia are deducted from the reductions in NO_X emissions. EPA and the Department do not recognize the latter method, although the point is appreciated.
- General Electric estimates that for units designed for fuel oil as stand-by fuel, the costs are much higher than estimated by KUA. They believe that any amount of fuel oil firing will significantly increase costs because heat recovery steam generator maintenance costs will increase. This is due to fouling by sticky ammonium sulfate and bisulfate residue.[21]
- According to estimates by other consultants, the cost of reducing slip from 10 (the basis of KUA's estimate) to 5 or 2 ppmvd would add $600 to 2900 per ton of NO_X removed[22, 23]
- At $6,000 to 8,300 per ton (after adjusting the KUA estimate for slip control), the Department does not believe it is cost-effective to reduce emissions to 3.5 ppmvd with a slip of 2-5 ppmvd

- SCR causes environmental and energy impacts including increased particulate emissions. undesirable (though unregulated) ammonia emissions, and energy penalties. At equal emission rates, DLN technology is a better control strategy than SCR. At higher emission rates, DLN can still be justified as BACT given the cost-effectiveness estimates above together with the negative effects of SCR described above.
- EPA Region IV advised the concerns above are valid. However EPA stated that the Department (in its first draft BACT) did not present "any unusual site-specific conditions associated with the KUA project to indicate that the use of SCR to achieve 3.5 ppmvd would create greater problems than experienced elsewhere at other similar facilities."[24]
- Region IV advised that (notwithstanding cost-effectiveness calculations) it considers SCR cost-effective on the basis that it has been required in many parts of the country without making projects economically unfeasible.[25] EPA advised that it intends to appeal the KUA Permit if the Department does not require a NO_X emissions rate of 3.5 ppmvd when firing natural gas.[26] EPA does not require or propose an ammonia slip limit.
- The Department notes that the EPA Region IV criterion for the BACT limit is most similar to the criterion applied in non-attainment areas where Lowest Achievable Emissions Rate (LAER) is applicable. According to mid-1998 correspondence from EPA Region IX to Goal Line, "any future combustion turbine co-generation project that is subject to the LAER requirement for NO_X must either achieve compliance with a 3.5 ppmv NO_X emission limit, or demonstrate that unique circumstances at the specific facility make compliance with a 3.5 ppmv NO_X emission limit technically infeasible."[27]
- 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).[28]
- The Department believes BACT for natural gas firing is 9 ppmvd by DLN or 4.5 ppmvd by SCR (with ammonia slip of 5 ppmvd). The values for the SCR option take into consideration the uncertainties mentioned above and minimize the negative effects of ammonia emissions.
- The recently-drafted Tier I BACT for all large combined cycle turbines prepared by Texas is 9 ppmvd by DLN or 5 ppmvd by SCR (with ammonia slip of 7 ppmvd). The proposal is based on the input from states, applicants, catalyst vendors, turbine manufacturers, etc.
- KUA elected to install SCR technology and meet a 3.5 ppmvd NO_X limit while firing natural gas as required by EPA.[29] The reason is that an appeal would delay issuance of the final permit by roughly one year. KUA has contractual commitments that cannot be met since construction cannot commence until the permit is issued.[30]
- The required NO_X reduction by SCR while firing gas is therefore from 9 to 3.5 ppmvd instead of from 9 to 4.5 ppmvd. More catalyst is normally required to meet the additional 22% reduction to meet EPA's requirement.
- The baseline NO_X limit for fuel oil firing is 42 ppmvd by wet injection. The Department estimates that more catalyst is required to meet the 15 ppmvd NO_X SCR-based limit while firing fuel oil than was required to meet 4.5 ppmvd while firing gas. A unit sized to reduce NO_X from 9 to 4.5 ppmvd while firing gas will only reduce NO_X from 42 to about 27 ppmvd while firing fuel oil. The extra catalyst already required to effect the "additional" 56% reduction to 15 ppmvd while firing fuel oil should be capable of accommodating a revised 3.5 ppmvd gas-based limit while maintaining the specified ammonia slip of 5 ppmvd.

- During intermittent simple cycle operation, the Department will permit NO_X emissions of 12 ppmvd. Prolonged operation of the unit in simple cycle mode will require that it meet the same 9 ppmvd limit by DLN through re-tuning.
- VOC emissions of 1.4 ppm from the combustion turbine by Good Combustion proposed by the Department are at the lower end of values determined as BACT. However even lower values have already been achieved by the previous generation DLN 2 combustors on the GE's 7FA units after tuning. Similar VOC performance is expected with the DLN-2.6 combustors while firing natural gas. The limit of 4 ppm with the duct burner in operation is also low. The 10 ppm limit while firing fuel oil is readily achievable whether the duct burner is on or off.
- The CO concentrations of 12 ppmvd are low with the duct burner off. With the duct burner on, they will be less than 20 ppmvd which is within the range of recent Department BACT determinations for combustion turbines alone. The CO limit, during the limited hours of fuel oil firing, will be set at 30 ppmvd whether or not the duct burner is in operation.
- For reference, CO limits for the Lakeland and Tallahassee projects are 25 ppmvd on gas while the limit for the FPL Fort Myers project is 12 ppmvd. Limits for the Santa Rosa Energy Center are 9 ppmvd with the duct burner off and 24 ppmvd with the large duct burner on. 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. Additionally, the higher emission mode will involve fuel oil firing which will occur substantially less than the permitted 720 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (3 and 24-hr averages)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)

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 NO_X standard. These excess emissions periods shall be reported as required in Specific Condition 32 of the Permit . A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C. and applicant request].

Excess emissions may occur under the following startup scenarios:

Hot Start: One hour in simple cycle or following a shutdown less than or equal to 8 hours.
Warm Start: Two hours following a shutdown between 8 and 48 hours.
Cold Start: Four hours following a shutdown greater than or equal to 48 hours.

The *starts* are defined by the amount of time the HRSG has been shutdown, following the normal (hot) shutdown procedure described by General Electric, prior to the startup.[31]

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section 11/22
Teresa Heron, Review Engineer, New Source Review Section

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Recommended By:

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

Date: 11/23/99

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 11/23/99

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Memorandum

Florida Department of Environmental Protection

TO: Howard Rhodes

THRU: Clair Fancy

FROM: A.A. Linero 11/22

DATE: November 22, 1999

SUBJECT: KUA Cane Island Unit 3
250 MW Combined Cycle Plant (PSD-FL-254)

Attached is the final package for construction of a 167 MW GE PG7241FA gas-fired combustion turbine at the KUA Cane Island Power Park near Intercession City, Osceola County. The project includes a heat recovery steam generator to achieve the 250 MW at referenced conditions. A 1.0 million gallon storage tank will be constructed for the back-up distillate fuel that will be used for no more than 720 hours per year. Supplemental duct firing and inlet air cooling will be employed at high ambient temperature to partially compensate for loss of power output.

The basic unit is a nominal 167 megawatt General Electric PG7241FA gas and oil-fired combustion turbine-generator. The project includes a supplementary-fired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 80-90 MW via a steam-driven electrical generator. A selective catalytic reduction system including ammonia storage is included.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by Dry Low NO_X (DLN-2.6) combustors capable of achieving emissions of 9 parts per million (ppmvd) by volume at 15 percent oxygen. The requirement to install SCR to achieve 3.5 ppmvd was included at the request of KUA. The ammonia limit for this option included in the Site Certification was preserved as 5 ppmvd.

Emissions of 15 ppmvd NO_X will be achieved during the limited fuel oil use. They may occasionally operate the unit in simple cycle mode. During such operation, they may emit 12 ppmvd while firing gas and 42 ppmvd while firing fuel oil. Extended simple cycle operation requires achievement of 9 ppmvd. Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and, especially, the design of the GE unit.

The Site Certification was approved on November 22. The attached permit is based on the version that was submitted at the administrative hearing and that forms the basis of the Site Certification. The exception is that the DLN and wet injection options are available under combined cycle operation and the SCR objective under combined cycle operation is 3.5 rather 4.5 ppmvd. I included the necessary EAB Appeal language in consultation with OGC.

I recommend your approval of the attached Permit and BACT Determination.

AAL/al

Attachments